COMMONWEALTH *of* VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

Molly Joseph Ward
Secretary of Natural Resources

NORTHERN REGIONAL OFFICE
13901 Crown Court, Woodbridge, Virginia 22193-1453
(703) 583-3800
www.deq.virginia.gov

David K. Paylor
Director

Thomas A. Faha
Regional Director

November 22, 2016

Mr. Jeffrey Heffelman
Director, Fossil and Hydro Systems
Dominion Ladysmith Combustion Turbine Station
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Location: Caroline County
Registration No.: 40960

Dear Mr. Heffelman:

Attached is an administrative amendment to the Title V permit to operate an electric generating facility pursuant to 9 VAC 5 Chapter 80, Article 3, of the Virginia Regulations for the Control and Abatement of Air Pollution. The amended permit reflects corrections to condition references in Conditions 42.a, 42.d-f and 50.c, typographical error in Condition 32.c(2), includes an additional regulatory reference citation in Condition 75 and also removes Conditions 115 through 118 ('Malfunction as an Affirmative Defense') of the Title V permit issued April 14, 2016. This amended Title V permit document supersedes your Title V permit document dated April 14, 2016.

The permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all permit conditions carefully.

In evaluating the application and arriving at a final decision to issue this amended permit, the Department deemed the application complete on August 16, 2016. Public notice and public participation were not required per 9 VAC 5-80-670.A.

This permit approval shall not relieve Dominion Ladysmith Combustion Turbine Station of the responsibility to comply with all other local, state and federal permit regulations.

Issuance of this permit is a case decision. The Regulations, at 9 VAC 5-170-200, provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this permit is mailed or delivered to you. Please consult this and other relevant provisions for additional requirements for such requests.

Additionally, as provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal to court by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P.O. Box 1105
Richmond, Virginia 23218

In the event that you receive this permit by mail, three days are added to the period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia, at http://www.courts.state.va.us/courts/scv/rules.html, for additional information including filing dates and the required content of the Notice of Appeal.

If you have any questions concerning this permit, please contact the regional office at (703) 583-3800.

Sincerely,

Thomas A. Faha

Thomas A. Faha
Regional Director

Attachment: Permit

c: Elizabeth A. Willoughby, Dominion Environmental Services (electronic file submission)
Director, OAPP (electronic file submission)
Director, Office of Permits and Air Toxics (3AP10), U.S. EPA, Region III (electronic file submission)

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Federal Operating Permit
Article 3

This permit is based upon Federal Clean Air Act acid rain permitting requirements of Title IV, federal operating permit requirements of Title V, and Chapter 80, Article 3 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13, 10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, 9 VAC 5-80-360 through 9 VAC 5-80-700 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution of the Commonwealth of Virginia.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name:	Virginia Electric and Power Company
Facility Name:	Dominion – Ladysmith Combustion Turbine Station
Facility Location:	8063 Cedon Road Woodford (Caroline County), Virginia 22580
Registration Number:	40960

Permit Number	Effective Date	Amendment Date	Expiration Date
NRO 40960	April 14, 2016	November 22, 2016	April 13, 2021

Thomas A. Faha
Regional Director

November 22, 2016
Signature Date

Permit consists of 70 pages.
Permit Conditions 1 to 137.
Table of Contents consists of 1 page.
Appendices A, B, C, D, and E

Table of Contents

Facility Information

Permittee
Virginia Electric and Power Company
DBA: Dominion Ladysmith Combustion Turbine Station
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Responsible Official
Jeffrey Heffelman
Station Director, Power Generation

Acid Rain Designated Representative
Mr. David A. Craymer
Vice President Power Generation System Operations

Alternate Acid Rain Designated Representative
Jeffrey Heffelman
Station Director, Power Generation

Cross State Air Pollution Rule (CSAPR) Designated Representative
Mr. David A. Craymer
Vice President Power Generation System Operations

Alternate CSAPR Designated Representative
Jeffrey Heffelman
Station Director, Power Generation

Facility
Dominion – Ladysmith Combustion Turbine Station
8063 Cedon Road
Woodford, Virginia 22580
Caroline County

Contact Person
Mr. Scott Lawton
Director, Electric Environmental Business Support
(804) 273-2600

Facility Description:
NAICS Code: 221112 – Electric Power Generation

Dominion operates five simple-cycle dual fuel combustion turbines (CTs) designated as Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5. Pipeline natural gas is the primary fuel with No.2

distillate fuel oil as the backup fuel. In addition to the five combustion turbines, the facility also operates two natural gas-fired pipeline heaters (PH-3 and PH-4) and three emergency diesel engine-powered generator sets (EDG1, EDG2, and EDG3).

Unit 1 and Unit 2 each commenced construction in the year 2000, and commenced operation in May 2001; Units 1 and 2 are each subject to the requirements of 40 CFR 60, Subpart GG. Unit 3 and Unit 4 each commenced construction in 2007; Unit 3 commenced operation in May 2008, while Unit 4 commenced operation in June 2008. Units 3 and 4 are each subject to the requirements of 40 CFR 60, Subpart KKKK. Unit 5 was constructed between 2008 and 2009, and began operation in March 2009; Unit 5 is subject to the requirements of 40 CFR 60, Subpart KKKK.

This source is located in Caroline County, an attainment area for all pollutants, and is a synthetic minor source under the Prevention of Significant Deterioration (PSD) regulations (9 VAC 5-80 Article 8) through a minor New Source Review Permit, most recently amended on August 18, 2015. For the purposes of an Article 3 Federal Operating Permit program (9 VAC 5-80-360), the source is classified as a major source for NO_X emissions.

The facility is subject to the requirements of the Acid Rain permitting program and the Cross-State Air Pollution Rule (CSAPR). The NO_X Trading Program was applicable to the facility on May 31, 2004 and then replaced by the Clean Air Interstate Rule (CAIR) in 2005, which rendered the NO_X Trading Program no longer applicable. On December 23, 2008, the U.S. Court of Appeals remanded CAIR to EPA. This action kept CAIR in force, but required EPA to develop a replacement rule, which addressed the courts order.

Effective January 1, 2015, CSAPR took effect and replaced CAIR. The CSAPR requires certain states (including the Commonwealth of Virginia) to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.

The Acid Rain Renewal Application, dated June 18, 2014, was received by the DEQ on June 25, 2014. The CAIR Renewal Application, dated June 18, 2014, was received by the DEQ on June 25, 2014. However, as noted above, the CAIR program was replaced by CSAPR and so the CAIR Renewal Application is no longer applicable. The requirements of the Acid Rain Program and CSAPR Program are incorporated into the federal operating permit.

The facility has also applied for alternate-operating scenarios for re-tuning of the CTs and fuel type transfers. These alternate-operating scenarios were approved and will apply while firing on both pipeline natural gas and on No.2 distillate fuel oil.

In addition, the facility applied for a custom fuel monitoring schedule for Unit 1 and Unit 2 in a letter to the Environmental Protection Agency (EPA), Region III dated December 3, 2002. EPA approved the custom fuel monitoring schedule for Unit 1 and Unit 2 in a letter dated December 17, 2002. Both letters are attached as a part of Appendix A to the permit.

Emission Units

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID[2, 3]	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment / Utility Units							
Unit 1	1	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 31, 2001	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_01	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_01	Nitrogen Oxides (as NO_2)	
Unit 2	2	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2000 and commenced operation on May 23, 2001	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_02	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_02	Nitrogen Oxides (as NO_2)	

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
Unit 3	3	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2007 and commenced operation on May 19, 2008	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_03	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_03	Nitrogen Oxides (as NO_2)	
Unit 4	4	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel CT constructed in 2007 and commenced operation on June 3, 2008	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_04	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit
			1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_04	Nitrogen Oxides (as NO_2)	
Unit 5	5	The CT is a GE Model PG7241 (FA) simple cycle, duel fuel, CT constructed in 2008 and 2009 and commenced	1,761 MMBtu/hr on pipeline natural gas (P)[4]	When firing pipeline natural gas – dry low NO_X burners, each unit	CD_LN_05	Nitrogen Oxides (as NO_2)	8/18/15 NSR permit

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
		operational on March 5, 2009	1,910 MMBtu/hr on No.2 distillate fuel oil (S)[4]	When firing No.2 distillate fuel oil – water injection, each unit	CD_WI_05	Nitrogen Oxides (as NO_2)	
PH-3	PHS3	Pipeline natural gas pipeline heaters. Constructed in 2007	10.75 MMBtu/hr	None	N/A	N/A	8/18/15 NSR permit
PH-4	PHS4	Pipeline natural gas pipeline heaters. Constructed in 2008	4.2 MMBtu/hr	None	N/A	N/A	8/18/15 NSR permit
EDG1	EDG1	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit
EDG2	EDG2	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity[1] (P)-Primary Fuel (S) Secondary Fuel	Pollution Control Device Description[1] (PCD)	PCD ID [2, 3]	Pollutant Controlled	Applicable Permit Date
EDG3	EDG3	Caterpillar C175-16 diesel engine-powered generator set	Engine output: 4,423 bhp Electrical output: 3,000 kW	None	N/A	N/A	8/18/15 NSR permit
T1	--	Fixed roof storage tank for No. 2 distillate oil	2,700,000 gallons	None	N/A	N/A	8/18/15 NSR permit
T2	--	Fixed roof storage tank for No. 2 distillate oil	2,700,000 gallons	None	N/A	N/A	8/18/15 NSR permit

1. Specifications included in this section are for informational purposes only and do not form enforceable terms or conditions of the permit
2. CD_LN = dry low NO_X burner technology
3. CD_WI = water injection
4. These figures are based upon the manufacturer's specifications at 100% base load, 59°F and 14.7 psia.

Fuel Burning Equipment Requirements – (Units 1 - 5, PH-3 & PH-4)

1. **Limitations** – *Nitrogen Oxide Emission Controls – CTs:* Nitrogen oxides (NO_X) emissions from each CT (Unit 1 – 5) while firing pipeline natural gas, shall be controlled by the utilization of a dry low NO_X combustor and water injection when firing on No.2 distillate fuel oil. The CTs shall be provided with adequate access for inspection.
   (9 VAC 5-80-490 B & C and Condition 1 of the 08/18/15 NSR Permit)

2. **Limitations** – *Nitrogen Oxide Emission Controls – Pipeline Heaters:* Nitrogen oxides (NO_X) emissions from each natural gas pipeline heater (PH-3 and PH-4), shall be controlled by the use of good combustion operating practices. The pipeline heaters shall be provided with adequate access for inspection.
   (9 VAC 5-80-490 B & C and Condition 2 of the 08/18/15 NSR Permit)

3. **Limitations** – *Sulfur Dioxide Emission Controls – CTs:* Sulfur dioxide (SO_2) emissions from each CT (Unit 1 – 5) shall be controlled by the use of pipeline quality natural gas as the primary and low sulfur No.2 distillate fuel oil as the secondary fuel.
   (9 VAC 5-80-490 B & C and Condition 4 of the 08/18/15 NSR Permit)

4. **Limitations** – *Sulfur Dioxide Emission Controls – Pipeline Heaters:* Sulfur dioxide (SO_2) emissions from each pipeline heater (PH-3 and PH-4) shall be controlled by the use of pipeline quality natural gas.
   (9 VAC 5-80-490 B & C and Condition 4 of the 08/18/15 NSR Permit)

5. **Limitations** – *Particulate Emission Controls – CTs:* Particulate matter (PM-10) emissions from each CT (Unit 1 – 5), shall be controlled by the use of pipeline quality natural gas as the primary fuel and No.2 distillate fuel oil as the back-up fuel along with good combustion operating practices.
   (9 VAC 5-80-490 B & C and Condition 6 of the 08/18/15 NSR Permit)

6. **Limitations** – *Particulate Emission Controls – Pipeline Heaters:* Particulate matter (PM-10) emissions from each pipeline heater (PH-3 and PH-4) shall be controlled by the use of pipeline quality natural gas and good combustion operating practices.
   (9 VAC 5-80-490 B & C and Condition 6 of the 08/18/15 NSR Permit)

7. **Limitations** – *Volatile Organic Compounds and Carbon Monoxide Emission Controls – CTs:* Volatile organic compounds (VOC) and carbon monoxide (CO) emissions from each CT (Unit 1 – 5) shall be controlled by the use of good combustion operating practices.
   (9 VAC 5-80-490 B & C and Condition 7 of the 08/18/15 NSR Permit)

8. **Limitations** – *Volatile Organic Compounds and Carbon Monoxide Emission Controls – Pipeline Heaters:* Volatile organic compounds (VOC) and carbon monoxide (CO) emissions from each natural gas pipeline heater (PH-3 and PH-4) shall be controlled by the use of good combustion practices.
   (9 VAC 5-80-490 B & C and Condition 7 of the 08/18/15 NSR Permit)

9. **Limitations** – *Combustion Turbines Fuels* – The approved fuels for the CTs (Unit 1 – 5) are pipeline quality natural gas (as defined in 40 CFR 72.2), as the primary fuel, and No.2 distillate fuel oil, (defined as fuel oil that meets the specifications for fuel oil numbers 1 or 2 under the American Society for Testing and Materials, most current version of ASTM D396 "Standard Specification for Fuel Oils" or other approved ASTM methods, incorporated in 40 CFR 60 by reference), as the back-up fuel. A change in fuel may require a permit to modify and operate.

   (9 VAC 5-80-490 B & C and Condition 13 of the 08/18/15 NSR Permit)

10. **Limitations** – *Pipeline Heaters Fuel* – The approved fuel for each pipeline heater (PH-3 and PH-4) is pipeline quality natural gas (as defined in 40 CFR 72.2). A change in fuel may require a permit to modify and operate.

    (9 VAC 5-80-490 B & C and Condition 14 of the 08/18/15 NSR Permit)

11. **Limitations** – *Number 2 Distillate Oil Specifications (Unit 1 and Unit 2)* – The maximum sulfur content of the No.2 distillate fuel oil shall not exceed 0.05 percent by weight per oil transfer/shipment receipt as defined in Appendix B.

    (40 CFR 60.333, 9 VAC 50-410, 9 VAC 5-80-490 B & C, and Condition 18 of the 08/18/15 NSR Permit)

12. **Limitations** – *Number 2 Distillate Oil Specifications (Unit 3, Unit 4, and Unit 5)* – The maximum sulfur content of the No.2 distillate fuel oil shall not exceed 0.060 lb SO_2/MMBtu heat input.

    (40 CFR 60.4330, 9 VAC 5-80-490 B & C, and Condition 19 of the 08/18/15 NSR Permit)

13. **Limitations** – *Pipeline Natural Gas Specifications (Unit 1 and Unit 2)* – The maximum sulfur content of the pipeline natural gas shall not exceed 20 grains per 100 dry standard cubic feet. The annual average sulfur content of the pipeline natural gas shall not exceed 0.5 grains per 100 dry standard cubic feet per year, calculated monthly as the average of each consecutive twelve-month period. Compliance with the consecutive twelve-month period shall be demonstrated monthly by averaging the total for the most recently completed calendar month to the individual monthly totals for the preceding eleven months.

    (40 CFR 60.333, 9 VAC 5-50-410, 9 VAC 5-80-490 B & C, and Condition 16 of the 08/18/15 NSR Permit)

14. **Limitations** – *Pipeline natural gas Specifications (CTs Unit 3, Unit 4, Unit 5 and Pipeline Heaters PH3 and PH4):* The maximum sulfur content of the pipeline natural gas shall not exceed 0.060 lb SO_2/MMBtu heat input.

    (40 CFR 60.4330, 9 VAC 5-80-490 B & C and Condition 17 of the 08/18/15 NSR Permit)

15. **Limitations** – *Fuel Tanks (T1 and T2)* – The two 2,700,000 gallon fixed-roof storage tanks (T1 and T2) shall be used to store only No.2 distillate fuel oil with a sulfur content not to exceed 0.05 percent by weight.

    (9 VAC 5-80-490 B & C and Condition 21 of the 08/18/15 NSR Permit)

16. **Limitations** – *Requirements by Reference* – Except where this permit is more restrictive than the applicable requirement, Unit 1 and Unit 2 shall be operated in compliance with the requirements of40 CFR 60, Subpart GG – Standards of Performance for Stationary Gas Turbines and 40 CFR 60, Subpart A – General Provisions.
(9 VAC 5-50-400, 9 VAC 5-50-410 and Condition 22 of the 08/18/15 NSR Permit)

17. **Limitations** – *Requirements by Reference* – Except where this permit is more restrictive than the applicable requirement, Unit 3, Unit 4, and Unit 5 shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Gas Turbines and 40 CFR 60, Subpart A – General Provisions.
(9 VAC 5-50-400, 9 VAC 5-50-410 and Condition 23 of the 08/18/15 NSR Permit)

18. **Limitations** –*Requirements by Reference* – Except where this permit is more restrictive than the applicable requirement, the pipeline heater (PH3) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc (Standards of performance for Small Industrial-Commercial-Institutional Steam Generating Units).
(9 VAC 5-80-490 B & C and Condition 24 of the 08/18/15 NSR Permit)

19. **Limitations** – *Alternate Operating Scenario – Re-tuning*:

a. Alternate 1 while operating on Natural Gas – (Units 1 – 5) – Re-tuning of the CTs shall be conducted in accordance with those procedures outlined in Appendix C of this permit.

b. Alternate 2 while operating on No. 2 Distillate Oil 9 (Units 1 – 5) – Re-tuning of the CTs shall be conducted in accordance with those procedures outlined in Appendix C of this permit.

Excess emissions resulting from the re-tuning of the combustion turbines shall be permitted provided that:

c. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbine (CT) re-tuning event in any twenty-four hour period. The operator may request additional hours from the DEQ.

d. During each CTs (Unit 1 and Unit 2) re-tuning event, NO_X emission concentrations, based on a four hour average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (60.330 et seq.).

e. During each CTs (Units 3 – 5) re-tuning event, NO_X emission concentrations, based on a four hour average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

f. Other Excess Emissions – Other excess emissions resulting from the re-tuning of each combustion turbine shall be permitted provided that the procedures specified in Appendix C are followed.

(9 VAC 5-50-50E, 9 VAC 5-80-490F, and Condition 25 of the 08/18/15 NSR Permit)

20. **Limitations** – *Alternate Operating Scenario – Fuel Type Transfer (Units 1 – 5)* – Fuel type transfer shall be conducted in accordance with the following procedures (See Appendix D):

a. Event 1 – Automatic or Operator Initiated Fuel Transfer from Pipeline Natural Gas to No. 2 Distillate Fuel Oil: The period will begin when gas usage is first reduced for the purpose of transferring to No.2 distillate fuel oil and will end when No.2 distillate fuel oil consumption and water injection have stabilized.

b. Event 2 – Operator Initiated Fuel Transfer from No. 2 Distillate Fuel Oil to Pipeline Natural Gas: The period will begin when the turbine's work load is reduced for the purpose of transferring to natural gas and will end when No.2 distillate fuel oil usage ceases and the turbine is re-stabilized in Mode 6 for Dry Low NO_X Burners.

c. Excess NO_X Emissions – Excess NO_X emissions from each combustion turbine shall be limited to no more than three one-hour averaging periods for any fuel type transfer event, unless specifically authorized by DEQ for longer duration prior to the event, however, in no case shall the NO_X emissions exceed the limits specified in 40 CFR 60, Subpart GG for Unit 1 and Unit 2 and 40 CFR 60, Subpart KKKK for Unit 3, Unit 4, and Unit 5. For each fuel type transfer event, the permittee shall:

(1) Operate all equipment in a manner consistent with air pollution control practices for minimizing emissions.

(2) Within thirty days of any changes in the procedures outlined in Appendix D of this permit, notify and provide a general description of the new procedures to be followed during periods of fuel type transfer to ensure that the best operational practices to minimize emissions will be adhered to and the duration of excess emissions will be minimized.

(3) The description shall be submitted to the DEQ at the address specified in Condition 46.

(4) Excess emissions during the fuel type transfer will be recorded and included in the quarterly Excess Emission Report. The CEM data will be "flagged" to indicate that fuel type transfer took place.

d. Other Excess Emissions – Other excess emissions resulting from the fuel type transfer for each combustion turbine shall be permitted provided that the procedures specified in Appendix D of this permit are followed.

(9 VAC 5-20-180 J, 9 VAC 5-50-20 E, 9 VAC 5-80-490F, and Condition 26 of the

08/18/15 NSR Permit)

21. **Limitations -** *Alternate Operating Scenario – Low Load Emergency (LLE) Mode (Ref. Nos. Units 1 – 5)* – During electric grid restoration, the combustion turbines (CT's) may operate for an extended period of time at a low startup load. This scenario of operation is known as low load emergency (LLE) mode. LLE mode may be tested once each calendar year. A successful test is considered to be a sustained generation from the CT's while operating in LLE mode. The turbines may be operated in LLE mode during a Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) Independent System Operator's (ISO) declared emergency and during the once per calendar year LLE mode test.

    (9 VAC 5-80-490F, Virginia Code 10.1-1307.02, Virginia Code 10.1-1307.3.A.5, and Condition 17 of the 08/18/15 NSR Permit)

22. **Limitations –** *Short-term emission limits* – The operation of Unit 1 and Unit 2 while firing on pipeline natural gas shall not exceed the limits specified below (except during start-up and shut-down conditions as defined in Condition 26, fuel type transfer in accordance with Condition 20, re-tuning in accordance with Condition 19, and LLE mode events as defined in Condition 21):

PM-10	18 lbs/hr	(9 VAC 5-50-260)
Nitrogen Oxides	9 ppmvd@ 15% O_2 (1 hour average)	(9 VAC 5-50-260)
Carbon Monoxide	9 ppmvd@ 15% O_2 (3 hour average)	(9 VAC 5-50-260)

(40 CFR 60.332, 9VAC5-80-490 B & C, and Condition 28 of the 08/18/15 NSR Permit)

23. **Limitations –** *Short-term emission limits* – The operation of Unit 3, Unit 4, and Unit 5 while firing on pipeline natural gas shall not exceed the limits specified below (except during start-up and shut-down as defined in Condition 26, re-tuning in accordance with Condition 19, fuel type transfer in accordance with Condition 20, and LLE mode events as defined in Condition 21):

PM-10	18 lbs/hr	(9 VAC 5-50-260)
Sulfur Dioxide	0.060 lb/MMBtu	(9 VAC 5-50-260)
Nitrogen Oxides	9 ppmvd@ 15% O_2 (1 hour average)	(9 VAC 5-50-260)
Carbon Monoxide	9 ppmvd@ 15% O_2 (3 hour average)	(9 VAC 5-50-260)

(40 CFR 60.4325, 9 VAC 5-80-490 B & C and Condition 29 of the 08/18/15 NSR Permit)

24. **Limitations –** *Short-term emission limits* – The operation of Unit 1 and Unit 2 while firing on No.2 distillate fuel oil shall not exceed the limits specified below (except during start-up and shut-down conditions as defined in Condition 26, re-tuning in accordance with Condition 19, and fuel type transfer in accordance with Condition 20, and LLE mode events as defined in Condition 21):

PM-10	34 lbs/hr	(9 VAC 5-50-260)
Nitrogen Oxides	42 * ppmvd@ 15% O_2 (1 hour average)	(9 VAC 5-50-260)
Carbon Monoxide	30 ppmvd@ 15% O_2 (3 hour average)	(9 VAC 5-50-260)

*See Condition 31 for Nitrogen Oxides calculation.

(40 CFR 60.332, 9 VAC 5-80-490 B & C and Condition 30 of the 08/18/15 NSR Permit)

25. **Limitations –** *Short-term emission limits* – The operation of Unit 3, Unit 4, and Unit 5 while firing on No.2 distillate fuel oil shall not exceed the limits specified below (except during start-up and shut-down conditions as defined in Condition 26, re-tuning in accordance with Condition 19, fuel type transfer in accordance with Condition 20, and LLE events as defined in Condition 21):

PM-10	34 lbs/hr	(9 VAC 5-50-260)
Sulfur Dioxide	0.060 lb/MMBtu	(9 VAC 5-50-260)
Nitrogen Oxides	42 * ppmvd@ 15% O_2 (1 hour average)	(9 VAC 5-50-260)
Carbon Monoxide	30 ppmvd@ 15% O_2 (3 hour average)	(9 VAC 5-50-260)

*See Condition 31 for Nitrogen Oxides calculation.

(40 CFR 60.4325, 9 VAC 5-80-490 B & C and Condition 31 of the 08/18/15 NSR Permit)

26. **Limitations –** Start-up and shut-down (Unit 1 – 5):

a. Start-up is defined as the period commencing with ignition of the unit and consisting of two hours of continuous emission monitoring system (CEMS) data.

b. Shut-down is defined, as the period comprised of the final two hours of CEMS data prior to the time when no fuel is being combusted.

(9 VAC 5-80-490 B & C and Condition 28 of the 08/18/15 NSR Permit)

27. **Limitations** – *Excess Emissions – Malfunctions* – Excess emissions resulting from unit startups, shutdowns and malfunctions shall be permitted provided that:

a. Units 1 – 5: Best operational practices are adhered to and the duration of excess emissions shall be minimized.

b. Unit 1 and Unit 2: During each malfunction, NO_X emission concentrations based on hourly averages (4-hour rolling averages) shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60.332 of Subpart GG.

c. Units 3 – 5: During each malfunction, NO_X emission concentrations based on hourly averages (4-hour rolling averages) shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60, Table 1 of Subpart KKKK.

d. Units 1 – 5: The permittee shall notify the DEQ within four daytime business hours after a malfunction is discovered. The notification shall include, but is not limited to, the following information:

(1) Identification of the specific CT experiencing the malfunction.

(2) The nature and quantity of emissions of air pollutants likely to have occurred during the malfunction.

(3) Measures that will be taken to minimize the length of the malfunction.

e. Units 1 – 5: The permittee shall include the excess emissions in the quarterly report and shall include, but is not limited to, the following information:

(1) Identification of the CT that experienced the malfunction.

(2) The magnitude of excess emissions per CT, any conversion factors used in the calculation of the excess emissions, and the date and time of commencement and completion of each period of excess emissions.

f. Units 1 – 5: NO_X emissions during each malfunction shall be recorded and included in the total annual emissions.

g. Units 1 – 5: The excess emissions resulting from a malfunction for each CT shall be identified in the quarterly excess emissions report.

(9 VAC 5-20-180 J, 9 VAC 5-50-20 E, 9 VAC 5-80-490F, and Condition 54 of the 08/18/15 NSR Permit)

28. **Limitations** – Annual emission limits:

a. Combined emissions from the operation of Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5 shall not exceed the limits specified below:

Sulfur Dioxide (SO_2)	74.4 tons/yr
Nitrogen Oxides (as NO_2)	237 tons/yr
Carbon Monoxide (CO)	119 tons/yr
Particulate Matter (PM-10)	73.8 tons/yr
Volatile Organic Compounds (VOC)	11.5 tons/yr

b. NO_X emission rate calculations for Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5 shall be calculated daily as the sum of each consecutive 365-day period. Compliance determination with the annual NO_X limit shall be determined using the NO_X mass emission provisions of 40 CFR Part 75, Subpart H, with the exception of data substitution as described in Condition 35 of this permit.

c. SO_2, CO, PM-10, and VOCs emission rate calculations for Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5 shall be calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding eleven months.

(9 VAC 5-20-180 J, 9 VAC 5-50-20 E, 9 VAC 5-80-490F, and Condition 32 of the 08/18/15 NSR Permit)

29. **Annual Emission Limits** – Facility wide:

a. Total emissions from the combined operation of all the fuel burning equipment (Units 1-5, PH-3 &4, and EDG1 through EDG3) at the Ladysmith Combustion Turbine Station shall not exceed the limits specified below:

Sulfur Dioxide (SO_2)	74.4 tons/yr
Nitrogen Oxides (as NO_2)	248.2 tons/yr
Carbon Monoxide (CO)	124.6 tons/yr
Particulate Matter (PM-10)	74.3 tons/yr
Volatile Organic Compounds (VOC)	11.8 tons/yr

b. The total facility wide annual emissions shall be calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding eleven months.

(9 VAC 5-80-490B & C and Condition 33 of the 08/18/15 NSR Permit)

30. **Limitations** –*Visible Emissions Limit* – Visible emissions from each of the CT stacks (Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5) shall not exceed ten percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed twenty percent opacity as determined by the Environmental Protection Agency (EPA) reference Method 9 (40 CFR 60, Appendix A). This condition applies at all times except during: start-up and shutdown as defined in Condition 26, fuel type transfers, re-tuning, LLE mode events, and malfunction.
(9 VAC 5-80-490 B & C and Condition 35 of the 08/18/15 NSR Permit)

31. **Limitations** – *NO_X Emission Limits* – NO_X emissions (as NO_2) from each CT (Unit 1 – 5) when firing No.2 distillate fuel oil, shall not exceed 42 ppmvd at 15% O_2 on a one hour average basis (as measured by CEMS), when fuel bound nitrogen (FBN) values are less than or equal to 0.015%. If the source wishes to account for the FBN allowance as provided in NSPS 40 CFR 60, Subpart GG, for FBN values up to 0.05% (the maximum FBN allowed), the adjusted standard shall be determined, recorded, and maintained upon each new fuel delivery by the following formula:

$$Standard = (0.04 * N) + 0.0042$$

Where:

Standard	=	allowable NO_X emissions (percent by volume at 15% O_2 and on a dry basis)
N	=	the nitrogen content of the fuel oil (percent by weight)

Note: 0.0042 percent = 42 ppm

Modifying the NOx limit by accounting for the fuel bound nitrogen as in paragraph 40 CFR 60.332 (a)(1) and (a)(2) is optional. The owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with 40 CFR 60.332 (a)(4) or may accept an F-value of zero.
(9 VAC 5-80-490 B & C, 40 CFR 60.332, and Condition 34 of the 08/18/15 NSR Permit)

32. **Monitoring** – *Opacity (Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5)* –

a. The permittee shall perform a visible emission observation (VEO) on each exhaust stack of CTs (Units 1 – 5) once each day during daylight hours that the CTs are operated. The VEO shall be based on the techniques of an EPA Method 22. Each VEO shall be performed for a sufficient period of time to identify the presence or absence of visible emissions.

b. If no visible emissions are observed, no action shall be required.

c. If visible emissions are observed, a visible emissions evaluation (VEE) shall be conducted using 40 CFR Part 60, Appendix A, Method 9 for a period of not less than 6-minutes.

(1) If the average opacity exceeds 20%, modifications and/or repairs to the CT shall be performed to correct the problem and the corrective measures shall be recorded;

(2) Following any corrective measures, a VEE in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be performed for a period of at least 18 consecutive minutes to determine compliance with the opacity limits specified in this permit;

(3) The follow-up VEE, if required, shall be conducted by a currently certified Visible Emission Evaluator.

(9 VAC 5-80-490 B & C and Condition 44 of the 08/18/15 NSR Permit)

33. **Monitoring –** *NO_X CEMS (Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5):*

a. CEMS shall be installed, maintained and operated in accordance with the performance specifications and test procedures (as applicable) identified in 40 CFR 75, Appendices A and B and shall measure and record the emissions of nitrogen oxides from the exhaust stack of Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5. A diluent monitor (O_2 or CO_2) shall be co-located with each nitrogen oxide monitor.

b. The CEMS shall be installed, maintained, calibrated, and operated in accordance with the performance specifications and test procedures (as applicable) identified in 40 CFR 75, Appendices A and B. Upon request by the DEQ, the source shall conduct CEMS performance tests. A thirty day notification, prior to the demonstration of the CEMS performance shall be submitted to the DEQ. Two copies of the performance test evaluation reports (one hard copy and one copy on electronic media) shall be submitted to the DEQ.

c. The quality assurance of data generated by the CEMs shall be demonstrated by implementing or exceeding the minimum requirements for CEMS quality assurance as defined in 40 CFR 75, Appendix B. A NO_X CEMS quality control program which meets the requirements of 40 CFR 75 and 40 CFR 75, Appendix B, shall be implemented for all continuous monitoring systems. As per 40 CFR 75, Appendix B §2.2.3f, no more than four successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 will elapse without performing a NO_X and O_2 or CO_2 analyzer linearity check. As per Part 75, Appendix B §2.3.3a.4, no more than eight successive calendar quarters plus the allowable grace period allowed in 40 CFR Part 75 shall elapse without performing a NO_X CEMS RATA.

(9 VAC 5-80-490 E, 40 CFR 60.334(b), 40 CFR 60.4335, and Condition 39 of the 08/18/15 NSR Permit)

34. **Monitoring –** *NO_X CEMs* – At the discretion and approval of the Board, the NO_X CEMs required by this permit, the continuous monitoring data, and the quality assurance data shall be used to determine compliance with the NO_X emission limits and/or relevant emission standards. Each monitor is subject to such data capture requirements and/or quality assurance requirements as specified in this permit and as may be deemed appropriate by the Board.

    (9 VAC 5-80-490 E and Condition 38 of the 08/18/15 NSR Permit)

35. **Monitoring** *–CEMS Minimum Data Capture* – The NO_X CEMS required by this permit shall meet a minimum data capture of 90% of each CTs operating hours, calculated monthly as the sum of each consecutive twelve-month period. Compliance for the consecutive twelve-month period shall be demonstrated monthly by adding the total available CEM operating hours for the most recently completed calendar month to the total available CEM operating hours for the preceding eleven months, divided by the total unit operating hours for the most recently completed calendar month, plus the total unit operating hours for the preceding eleven months, multiplied by one hundred.

    (9 VAC 5-80-490 E and Condition 40 of the 08/18/15 NSR Permit)

36. **Monitoring –** *NO_X CEMS Failure* – In the event of a NO_X CEMS failure, the permittee must either:

    a. Use the maximum allowable hourly NO_X emission rate (in ppm), for each hour of operation where CEMS data is not available. This data shall be included in the rolling 365-day emission summation; or

    b. Provide data which demonstrates an accurate correlation between the water-to-fuel injection curve and actual emission rates. Upon approval of the DEQ, this curve can be used as surrogate CEM data for future emission calculations.

    (9 VAC 5-80-490 E and Condition 41 of the 08/18/15 NSR Permit)

37. **Monitoring –** *Fuel Consumption Instrumentation/Backup Method* – The permittee shall install and maintain instrumentation or have an available backup method approved by the DEQ, to indicate/determine and record the hourly pipeline quality natural gas and No.2 distillate fuel oil consumption (in scf/hour and gallons/hour) of each CT (when in operation) and the hours of operation while using each fuel. These records shall be kept on file at the facility for the most current five year period.

    (9 VAC 5-80-490 E and Condition 43 of the 08/18/15 NSR Permit)

38. **Monitoring** – Natural Gas Continuing Compliance – Unit 1 and Unit 2:

a. The permittee's custom fuel monitoring schedule for Unit 1 and Unit 2 has received approval from the Environmental Protection Agency (EPA) in accordance with 40 CFR Part 60, Subpart GG and is incorporated into this permit by reference. The permittee's custom fuel schedule is as follows:

(1) The permittee shall follow all applicable sulfur content determinations for pipeline natural gas in 40 CFR Part 75, Appendix D.

(2) The requirement to determine the nitrogen content of the pipeline natural gas is waived.

b. The permittee recognizes that Subpart GG establishes the following sulfur dioxide (SO_2) emission limitations:

(1) No owner or operator shall cause to be discharged into the atmosphere from any stationary gas turbine any gasses containing SO_2 in excess of 0.015% by volume at 15% oxygen and on a dry basis; or,

(2) No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight.

c. If there is a change in fuel supply the permittee must notify the DEQ of such change for re-examination of this custom fuel monitoring schedule. A change in fuel quality may be deemed a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom fuel monitoring schedule is being re-examined.

d. As per 40 CFR 60.334(h)(3) and not withstanding 40 CFR 60.334(h)(1), the owners or operators may elect not to monitor more frequently than once per year (40 CFR 75, Appendix D, Section 2.3.1.4 or 2.3.2.4) for the total sulfur content of the gaseous fuel combusted in a turbine if the gaseous fuel is demonstrated to meet the definition of natural gas in 60.331(u), regardless of whether an existing custom schedule approved by the administrator for Subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration.

(1) The gas quality characteristics in a current valid purchase contract, tariff sheet or transportation contract for gaseous fuel specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(2) Have representative fuel sampling data which shows that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR 75 shall be obtained.

These records shall be available on-site for inspection by the DEQ and kept on file for the most current five year period.
(9 VAC 5-80-490 E, 40 CFR 60.334(h), 40 CFR 60.334(i)(3) and Condition 48 of the 8/18/15 NSR Permit and EPA letter dated 12/17/02)

39. **Monitoring** – *Natural Gas Continuing Compliance* – Unit 3, Unit 4, Unit 5, PH-3, and PH-4:

a. The permittee will follow all applicable sulfur content determinations and monitoring requirements for pipeline natural gas in 40 CFR Part 75, Appendix D.

b. If there is a change in fuel supply the permittee must notify the DEQ at the address listed in Condition 46. A change in fuel quality may be deemed a change in fuel supply and this change in fuel may require a reevaluation of the permit.

c. The owners or operators must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Condition 39 d of this permit.

(1) The sulfur content of the fuel must be determined using total sulfur methods described in 40 CFR 60.4415.

(2) Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17) or other approved method incorporated in to 40 CFR Part 60 by reference, which measure the major sulfur compounds, may be used.

d. The owners or operators may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input. You must use one of the following sources of information to make the required demonstration:

(1) The fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum total sulfur content for oil is 0.05 weight percent (500 ppm), the total sulfur content for pipeline natural gas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 0.060 lb SO_2/MMBtu heat input; or

(2) Conduct representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR 75 is required.

These records shall be available on-site for inspection by the DEQ and kept on file for the most current five year period.

(9 VAC 5-50-30 G, 40 CFR 60.4330, 40 CFR 60.4360, 40 CFR 60.4365, Condition 20 and Condition 48 of the 08/18/15 NSR Permit)

40. **Monitoring –** No. 2 Distillate Fuel Oil's Nitrogen and Sulfur Content: Continuing Compliance –

a. Unit 1 and Unit 2

(1) Prior to combustion, the permittee shall test the No.2 distillate fuel oil for sulfur content (and nitrogen content if the source chooses to account for the FBN allowance provided in NSPS Subpart GG), on each occasion that fuel is transferred (as defined in Appendix B of this permit) to the storage tank, from any other source. Fuel oil sulfur content shall be determined using ASTM D 2880-78, ASTM D 2880-96 or another approved ASTM method incorporated in 40 CFR 60.17 by reference or incorporated in 40 CFR 60.355(b)(10)(i). If applicable, fuel oil nitrogen content shall be determined by following current ASTM procedures approved by the Administrator of the EPA. Any deviations to test methods used by the permittee to determine sulfur and nitrogen content shall be submitted to the DEQ, at the address listed in Condition 46, for approval.

(2) These records shall be available on-site for inspection by the DEQ and kept on file for the most current five year period.

b. Unit 3, Unit 4, and Unit 5

(1) The total sulfur content of the fuel being fired in the turbine, except as provided in Condition 40.b.(2) (below), must be determined. The sulfur content of the fuel must be determined using total sulfur methods described in 40 CFR 60.4415.

(2) The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil is 0.05 weight percent (500 ppmw) or, has potential sulfur emissions of less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of 40 CFR 75 Appendix D is required.

(3) These records shall be available on-site for inspection by the DEQ and kept on file for the most current five year period.

(9 VAC 5-80-490 E, 40 CFR 60.40 CFR 60.4360, 40 CFR 60.4365, and Condition 49 of the 08/18/15 NSR Permit)

41. **Monitoring –** *Fuel Certification* – The permittee must use one of the following combination of sources (a and b, or a and c, below) of information to demonstrate compliance with Conditions 11 through 14:

a. No. 2 Distillate Fuel Oil (Unit 1 and Unit 2) - The permittee shall obtain a certification from the fuel supplier and/or the fuel oil delivery company with each shipment of No. 2 distillate fuel oil. Each fuel supplier certification shall include the following:

(1) The name of the fuel supplier/fuel delivery company;

(2) The date on which the No. 2 distillate fuel oil was received;

(3) The quantity of No. 2 distillate fuel oil delivered in the shipment;

(4) A statement that the No. 2 distillate fuel oil complies with the American Society for Testing and Materials specifications (ASTM D396) for Numbers 1 and 2 fuel oil or other approved ASTM method incorporated in 40 CFR 60 by reference; and;

(5) The actual sulfur content of the No. 2 distillate fuel oil or, upon last delivery of the No. 2 distillate fuel oil, the permittee shall collect an oil sample from the on-site fuel oil storage tank for use in determining the fuel oil sulfur content.

AND

b. Fuel Oil and Natural Gas (Units 3 – 5)

(1) The fuel characteristic in a current, valid purchase contract, tariff sheet or transportation contract for the natural gas, specifying that the maximum total sulfur content for the natural gas is 20 grains of sulfur or less per 100 standard cubic feet.

(2) For the No. 2 distillate fuel oil, a valid purchase contract, tariff sheet or transportation contract which shows the fuel oil being burned contains 500 parts per million (0.05% by weight) or less sulfur.

OR

c. Fuel Oil and Natural Gas (Unit 3 – 5) – Representative fuel sampling data, which shows that the sulfur content of the fuels does not exceed 0.060 lb SO_2/MMBtu heat input.

(9 VAC 5-80-490 F and Condition 20 of the 08/18/15 NSR Permit)

42. **Recordkeeping** – The permittee shall maintain records of all emission data and operating parameters necessary to demonstrated compliance with this permit. The content of and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to the following:

a. All fuel records to demonstrate compliance with Conditions 9 through 14 and 38 through 41.

b. The hourly fuel consumption (in scf/hr of pipeline natural gas and gallons/hr of No.2 fuel oil) of each CT (Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5) to demonstrate compliance with Condition 37.

c. Monthly fuel consumption (in scf/hr of pipeline natural gas) of the pipeline heater (PH3).

d. All data and calculations necessary to demonstrate compliance with the emission limits contained in Conditions 22 through 25, 28 and 29. These records shall include, but are not limited to the following:

(1) The times of operation of each CT when firing with No.2 distillate fuel oil.

(2) Hourly throughput of No.2 distillate fuel oil and natural gas to each CT, for purposes of calculating hourly emissions for pollutants for which there is not a continuous emissions monitor.

(3) Annual throughput of distillate fuel oil and natural gas for each CT, calculated monthly as the total for the most recent twelve complete calendar months.

e. Monthly emissions calculations for PM-10, sulfur dioxide, carbon monoxide, and VOC from the CTs stacks using calculation methods approved by the DEQ to verify compliance with the lb/hr and ton/yr emission limitations in Conditions 22 through 25, 28 and 29. These calculation methods may use the hourly operation information above and the most recent stack test information or AP-42, as determined to be appropriate by the DEQ.

f. All valid purchase contracts, tariff sheets or transportation contracts for the fuels, specifying that the maximum sulfur content of the natural gas as required in Conditions 38 and 39.

g. All records of the occurrence and duration of any bypass, malfunction, shutdown, or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record as required in Condition 48.

h. All records of each occurrence of control equipment scheduled maintenance in which the control equipment will be shut down or bypassed or both which will result in excess emissions for more than one hour. The records shall include, but not limited to the following:

(1) Identification of the air pollution control equipment to be taken out of service using the PCD ID number from the Emission Units Table on Page 5, as well as its location, and registration number of the facility;

(2) The expected length of time that the air pollution control equipment will be out of service;

(3) The nature and quantity of emissions of air pollutants likely to occur during the shutdown period; and

(4) Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

i. All records of excess emissions to include date, time, cause, and corrective action taken to alleviate the excess emissions.

j. All records of scheduled and unscheduled maintenance.

k. All records of VEOs shall recorded and shall contain the date, time, results of the VEO, description of any modifications and/or repairs, if necessary to correct any problem, and all follow-up VEE records including name of certified observer, date, time, results of follow-up VEE and operating parameters necessary to demonstrated compliance with this permit. The content of and format of such records shall be arranged with DEQ.

These records shall be available on site for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-490 F, 40 CFR 60.48c(g)(2), and Condition 50 of the 08/18/15 NSR Permit)

43. **Testing** – *Required Testing* – The permit does not require source tests. The DEQ and EPA have the authority to require testing necessary to determine compliance with an emission limit or standard at any reasonable time.
(9 VAC 5-80-490 E & F)

44. **Testing** – *Additional Requested Testing* - Upon request by the DEQ, or in accordance with federal requirements, the permitted facility shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-80-490 E, 9 VAC 5-80-490 F and Condition 45 of the 08/18/15 NSR Permit)

45. **Testing** – If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.
(9 VAC 5-80-490 E)

46. **Reporting** – All correspondence to the DEQ concerning this permit should be submitted to the following address:

Regional Air Compliance Manager
Department of Environmental Quality
Northern Regional Office
13901 Crown Court
Woodbridge, VA 22193

Unless otherwise specified in Condition 91, all correspondence to the EPA concerning this permit should be submitted to the following address:

U.S. Environmental Protection Agency, Region III
Air Protection Division (3AP12)
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-80-490 B & C)

47. **Reporting** – *NO_X CEMS* – Reports for Continuous Monitoring Systems (Units 1 – 5): The permittee shall furnish one hard copy and one electronic copy (using the contact information referenced in Condition 46) to the DEQ, of excess emissions from any process monitored by a CEMS, on a quarterly basis, postmarked no later than the thirtieth day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

a. For each month in the quarter, report each hour in which a NO_X permit limit is exceeded. The report shall include for each excess emission of NO_X: start time, duration, equipment involved, actual NO_X emissions in ppmvd @ 15% O_2, and fuel type.

b. If during the calendar quarter no excess emissions have occurred, or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

(9 VAC 5-80-490 F and Condition 42 of the 08/18/15 NSR Permit)

48. **Reporting** – *Equipment and Control Equipment Malfunctions* – The permittee shall furnish notification to the DEQ (at the address referenced in Condition 46), of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by e-mail, facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. A permittee subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C is not required to provide the written two week statement

for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the DEQ.
(9 VAC 5-80-490 F and Condition 60 of the 08/18/15 NSR Permit)

49. **Reporting** – *Control Equipment Maintenance* – The permittee shall furnish notification to the DEQ of the intention to shut down or bypass, or both, air pollution control equipment for necessary scheduled maintenance, which may results in excess emissions for more than one hour, at least twenty-four hours prior to the shutdown. The notification shall include, but is not limited to, the following information:

  a. Identification of the air pollution control equipment to be taken out of service using the PCD ID number from the Emission Units Table on Page 5, as well as its location, and registration number of the facility;

  b. The expected length of time that the air pollution control equipment will be out of service;

  c. The nature and quantity of emissions of air pollutants likely to occur during the shutdown period; and

  d. Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

  (9 VAC 5-80-490 F and Condition 61 of the 08/18/15 NSR Permit)

50. **Reporting** – Reporting of a Re-tuning Event:

  a. The permittee shall notify the DEQ, no less than twenty-four hours prior to each CTs re-tuning event. The notification shall include, but is not limited to, the following information:

    (1) Identification of the specific CT to be re-tuned.

    (2) Reason for the re-tuning event.

    (3) Measures that will be taken to minimize the length of the re-tuning event.

  b. The permittee shall furnish a written report to the DEQ of all pertinent facts concerning the re-tuning event, as soon as practicable but not later than fourteen business days after the re-tuning event. The notification shall include, but is not limited to, the following information:

    (1) Identification of the CT that was re-tuned.

    (2) The magnitude of excess emissions for each CT, any conversion factors used in the calculation of the excess emissions, and the date and time of commencement and completion of each period of excess emissions.

c. Excess emissions resulting from a re-tuning event for each CT, shall be recorded and included in the associated quarterly reports and in the total annual emissions as required in Conditions 28, 29 and 47.

(9 VAC 5-50-50 E, 9 VAC 5-80-490 F, and Conditions 25 and 53 of the 08/18/15 NSR Permit)

Emergency Engine-Generator Sets

51. **Limitations** – Nitrogen oxides (NO_X) emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by turbocharged engine and after-cooler. The permittee shall maintain documentation that demonstrates that turbo-charging and after-cooling equipment has been installed on the engine-generator sets.

    (9 VAC 5-80-490 B & C and Condition 3 of the 08/18/15 NSR Permit)

52. **Limitations** - Sulfur dioxide (SO_2) emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by the use of ultra low sulfur diesel (ULSD) fuel.

    (9 VAC 5-80-490 B & C and Condition 5 of the 08/18/15 NSR Permit)

53. **Limitations** - Visible emissions from the engine-generator sets (EDG1, EDG2 and EDG3) shall be controlled by the use of good operating practices and performing appropriate maintenance in accordance with the manufacturer recommendations over the entire life of each engine. In addition, the permittee may only change those settings that are approved by the manufacturer. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions.

    (9 VAC 5-80-490 B & C and Condition 8 of the 08/18/15 NSR Permit)

54. **Limitations** – The permittee shall operate and maintain each engine-generator set (EDG1, EDG2 and EDG3) according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer. In addition, the permittee may only change those settings that are permitted by the manufacturer and does not increase air emissions.

    (9 VAC 5-80-490 B & C, 40 CFR 60.4206, 40 CFR 60.4211, and Condition 10 of the 08/18/15 NSR Permit)

55. **Limitations** – Each engine-generator set (EDG1, EDG2 and EDG3) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12 month period. Compliance for the consecutive 12 month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

    (9 VAC 5-80-490 B & C and Condition 11 of the 08/18/15 NSR Permit)

56. **Limitations** – The engine-generator sets (EDG1, EDG2, and EDG3) shall only be operated in the following modes:

    a. When emergency power is required to start up the CT's in the event of failure of the electrical grid.

    b. In situations that arise from sudden and reasonably unforeseeable events where the primary energy or power source is disrupted or disconnected due to conditions beyond the control of an owner or operator of a facility including:

(1) A failure of the electrical grid;

(2) On-site disaster or equipment failure; or

(3) Public service emergencies such as flood, fire, natural disaster, or severe weather conditions.

c. For participation in an ISO-declared emergency, where an ISO emergency is:

(1) An abnormal system condition requiring manual or automatic action to maintain system frequency, to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property;

(2) Capacity deficiency or capacity excess conditions;

(3) A fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel;

(4) Abnormal natural events or man-made threats that would require conservative operations to posture the system in a more reliable state; or

(5) An abnormal event external to the ISO service territory that may require ISO action.

d. For periodic maintenance, testing, and operational training.

(9 VAC 5-80-490 B & C and Condition 12 of the 08/18/15 NSR Permit)

57. **Limitations** – The approved fuel for the engine-generator sets is ultra low sulfur diesel (ULSD) fuel that meets the specifications below:

a. ASTM D975 specification for S15 diesel fuel oil with a maximum sulfur content per shipment of 0.0015%; or

b. Has a maximum sulfur content not to exceed 0.0015% by weight (15 ppm), and either a minimum cetane number of forty or maximum aromatic content of thirty-five volume percent.

Exceedance of these specifications may be considered credible evidence of an exceedance of emission limits. A change in the fuel type or the fuel sulfur content may require a new or amended permit.
(9 VAC 5-80-490 B & C, 40 CFR 60.4207, and Condition 15 of the 08/18/15 NSR Permit)

58. **Limitations** – *Diesel Fuel (EDG1, EDG2, and EDG3)* – To determine compliance with Condition 57 the permittee shall obtain a certification from the fuel supplier with each shipment of diesel fuel. Each fuel supplier certification shall include the following:

a. The name of the fuel supplier;

b. The date on which the diesel fuel was received;

c. The quantity of diesel fuel delivered in the shipment; and

d. A statement that the diesel fuel complies with the American Society for Testing and Materials specifications (ASTM D975) for S15 diesel fuel oil; or the permittee shall obtain approval from the DEQ is other documentation will be used to certify the diesel fuel type.

(9 VAC 5-80-490 B & C, 40 CFR 60.4207, 40 CFR 60.4211, and Condition 20 of the 08/18/15 NSR Permit)

59. **Limitations** – Emissions from the operation of the engine-generator sets (EDG1, EDG2, and EDG3) shall not exceed the limits specified below:

	Each Genset		All Three Gensets Combined
Nitrogen Oxides (as NO_2)	50.7	lbs/hr*	38.0 tons/yr
Carbon Monoxide	6.2 lbs/hr	lbs/hr	4.7 tons/yr
Volatile Organic Compounds (VOC)	1.0 lbs/hr	lbs/hr	0.8 tons/yr

* This rate is less than 6.0 g/hp-hr at maximum load.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 67, 68 and 69.
(9 VAC 5-80-490 B & C and Condition 36 of the 08/18/15 NSR Permit)

60. **Limitations** – Visible emissions from each engine-generator set (EDG1, EDG2, and EDG3) exhaust shall not exceed 10% opacity except during one 6-minute period in any one hour in which visible emissions shall not exceed 20% opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown and malfunction).

(9 VAC 5-80-490 B & C and Condition 37 of the 08/18/15 NSR Permit)

61. **Limitations** – Except where this permit is more restrictive, the stationary reciprocating internal combustion engines (RICE) (EDG1, EDG2, and EDG3) shall be operated in compliance with the requirements of 40 CFR 63, Subpart ZZZZ.
(9 VAC 5-80-490 B & C and 40 CFR 63 Subpart ZZZZ)

62. **Limitations** - Each engine-generator set (EDG1, EDG2, and EDG3) must meet the requirements of 40 CFR 63 Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
(9 VAC 5-80-490 B & C and 40 CFR 63.6590(c))

63. **Limitations** – Except where this permit is more restrictive, each engine-generator set (EDG1, EDG2, and EDG3) shall be operated in compliance with the requirements of 40 CFR 60, Subpart IIII.
(9 VAC 5-80-490 B & C and 40 CFR 60 Subpart IIII)

64. **Limitations** - Emissions from the operation of each engine-generator set (EDG1, EDG2, and EDG3) shall not exceed the limits specified below:

	NSPS
Non-Methane Hydrocarbons (NMHC) + NO_x	4.0 g/kW-hr
CO	5.0 g/kW-hr
PM	0.30 g/kW-hr

The engines must be installed and configured according to the manufacturer's emission-related specifications. Compliance with these emission limits may be determined by keeping records of engine manufacture data indicating compliance with these emission limits.
(9 VAC 5-80-490 B & C, 40 CFR 60.4205(b), and 40 CFR 60.4211(c))

65. **Limitations** – The permittee must operate each emergency engine-generator set (EDG1, EDG2, and EDG3) according to the requirements of this Condition. In order for the engine to be considered an emergency stationary RICE, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in this Condition, is prohibited. If you do not operate the engine according to the requirements in this Condition, the engine will not be considered an emergency engine under 40 CFR 60 Subpart IIII and must meet all requirements for non-emergency engines:

a. You may operate your emergency engine-generator set for any combination of the purposes specified in (a)(1) through (a)(3) of this Condition for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by (b) of this Condition counts as part of the 100 hours per calendar year.

(1) Emergency engine-generator sets may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition DEQ for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(2) Emergency engine-generator sets may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see 40 CFR 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(3) Emergency engine-generator sets may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

b. The permittee may operate each emergency engine-generator set up to 50 hours per year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response. Except as provided in paragraphs (1) of this condition, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(1) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(a) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(b) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(c) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(d) The power is provided only to the facility itself or to support the local transmission and distribution system.

(e) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(9 VAC 5-80-490 B & C and 40 CFR 60.4211 (f))

66. **Monitoring** – Each engine-generator set (EDG1, EDG2, and EDG3) shall be equipped with a non-resettable hour metering device to monitor the operating hours. The non-resettable hour meter used to continuously measure the hours of operation for each engine-generator set shall be observed by the owner with a frequency of not less than once each day the engine-generator set is operated to ensure that the hour meter is functioning as intended. The owner shall keep a log of these observations. Each monitoring device shall be installed, maintained, calibrated (as appropriate) and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the engine-generator sets are operating.
(9 VAC 5-80-490 E, 40 CFR 60.4209, and Condition 9 of the 08/18/15 NSR Permit)

67. **Recordkeeping** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit for the engine-generator sets (EDG1, EDG2, and EDG3). The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to:

a. Annual hours of operation of each engine-generator set, calculated monthly as the sum of each consecutive 12 month period. Compliance for the consecutive 12 month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

b. All fuel supplier certifications.

c. Engine information including make, model, serial number, model year, maximum engine power (bhp), and engine displacement for each engine-generator set.

d. Records of engine manufacturer data as required in Condition 64.

e. The manufacturer's written operating instructions or procedures developed by the owner/operator that are approved by the engine manufacturer for each engine-generator set.

f. Records of the reasons for operation for each engine-generator set, including, but not limited to, the date, cause of operation, and the hours of operation.

g. Results of all stack tests and visible emission evaluations.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-490 F, 40 CFR 60.4214, and Condition 51 of the 08/18/15 NSR Permit)

68. **Testing** – Upon request by the DEQ, or in accordance with federal requirements, the permitted facility shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the DEQ.
(9 VAC 5-80-490 E and Condition 45 of the 08/18/15 NSR Permit)

69. **Testing** – The facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9 VAC 5-80-490 E and Condition 46 of the 08/18/15 NSR Permit)

70. **Testing** – Upon request by the DEQ, the permittee shall conduct a visible emissions evaluation (VEE) on the emergency engine-generator sets (EDG1, EDG2, and EDG3) in accordance with 40 CFR Part 60, Appendix A, Method 9, to demonstrate compliance with the applicable visible emission limits contained in this permit. The details of the VEE shall be arranged with the DEQ.
(9 VAC 5-80-490 E and Condition 47 of the 08/18/15 NSR Permit)

71. **Reporting** – The permittee shall furnish written notification to the DEQ of the actual start-up date of the engine-generator sets (EDG1, EDG2, and EDG3) within 15 days after such date. The actual start-up date shall be the date on which each engine completes manufacturer's trials, but shall be no later than thirty days after the initial start up for manufacturer's trials. Copies of the written notification are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-80-490 F and Condition 52 of the 08/18/15 NSR Permit)

72. **Reporting** – For the emergency engine-generator set (EDG1, EDG2, and EDG3) that operate or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in Conditions 65.a(2) and 65.a(3), the permittee must submit an annual report according to the following:

a. The report must contain the following information:

(1) Company name and address where the engine is located.

(2) Date of the report and beginning and ending dates of the reporting period.

(3) Engine site rating and model year.

(4) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(5) Hours operated, including the date, start time, and end time for engine operation for the purposes specified in Conditions 65.a(2) and 65.a(3).

(6) Number of hours the engine is contractually obligated to be available for the purposes specified in Conditions 65.a(2) and 65.a(3).

(7) If there were no deviations from the fuel requirements in Condition 57 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(8) If there were deviations from the fuel requirements in Condition 57 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

c. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to DEQ at the appropriate address listed in 40 CFR 63.13.

(9 VAC 5-80-490 F and 40 CFR 60.4214(d))

Facility-Wide Conditions

73. **Limitations** – *Maintenance and Operating Procedures* – At all times, including periods of start-up, shutdown and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

    The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations or good engineering practices, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9 VAC 5-80-490 and Condition 58 of the 08/18/15 NSR Permit)

74. **Limitations** – *Violation of Ambient Air Quality Standard* – The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
    (9 VAC 5-80-490 and Condition 62 of the 08/18/15 NSR Permit)

75. **Recordkeeping** – The permittee shall maintain records of all emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the DEQ. These records shall include, but are not limited to the following:

    a. Scheduled and unscheduled maintenance as required in Condition 73.

    b. All records of the required training including a statement of time, place and nature of training provided as required in Condition 73.

c. Good written operating procedures and a maintenance schedule for the CTs. These procedures shall be based on the manufacturer's recommendations, at minimum as required in Condition 73.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-80-490 and Conditions 50 and 51 of the 08/18/15 NSR Permit)

76. **Testing** – The permit does not require source tests. The DEQ and EPA has authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard at any reasonable time. The permitted facility shall be modified to allow for emissions testing at any time using appropriate methods. Upon request from the Department, test ports will be provided at the appropriate locations.
(9 VAC 5-50-30 and 9 VAC 5-80-490 E & F)

77. **Testing** – If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.
(9 VAC 5-80-490 E)

Insignificant Emission Units

78. **Insignificant Emission Units** – The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-490.

The following emission units at the facility are identified in the application as insignificant emission units under 9 VAC 5-80-720:

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
There are no insignificant emission units included in the permit; the two tanks (T1 and T2) listed as insignificant emission units in the permit application are subject to the requirements of Condition 15, and cannot be considered insignificant emission units.				

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110. (9 VAC 5-80-720 and 9 VAC 5-80-490 C, E, and F)

Permit Shield & Inapplicable Requirements

79. **Permit Shield and Inapplicable Requirements -** Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Non-Applicability
40 CFR 60 Subpart Dc (Pipeline Heater PH-4)	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input 100 MMBtu/hr less, but greater than or equal 10 MMBtu/hr. Since PH-4 is only 4.2 MMBtu this does not apply.
40 CFR 60 Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)	The storage vessels store liquids with a vapor pressure less than 3.5 kilopascals (0.5 psia).
40 CFR 63, Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Combustion Turbines	The facility is not a major source of HAPs
40 CFR 64	Compliance Assurance Monitoring	This permit requires CEMS to demonstrate compliance with permitted NOX emission limits for the CT units. Therefore these units are not subject to CAM per 40 CFR 64.2(b)(1)(vi).
9 VAC 5 Chapter 80, Article 7 and 9 VAC 5 Chapter 60, Article 3	Major HAPS NSR permitting	Not a major HAPS source.
40 CFR 68	Prevention of Accidental Chemical Releases	Any chemicals on-site are below threshold levels.

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by (i) the administrator pursuant to §114 of the federal Clean Air Act, (ii) the Board pursuant to §10.1-1314 or §10.1-1315 of the Virginia Air Pollution Control Law, or (iii) the Department pursuant to §10.1-1307.3 of the Virginia Air Pollution Control Law.
(9 VAC 5-80-500)

General Conditions

80. **Federal Enforceability** – All terms and conditions in this permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those that have been designated as only state-enforceable.
(9 VAC 5-80-490 N)

81. **Permit Expiration –** This permit has a fixed term of five years. The expiration date shall be the date five years from the date of issuance. Unless the owner submits a timely and complete application for renewal to the Department consistent with the requirements of 9 VAC 5-80-430, the right of the facility to operate shall be terminated upon permit expiration.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

82. **Permit Expiration** – The permit can be set to expire for a period of less than five years if required to bring the enforcement period into concurrence with other permitting programs. This Article 3 Title V/Title IV (Acid Rain) permit is a combined permit and therefore shall be issued to meet the enforcement period of the combined permitting programs and in this case the Title IV permit dates will dictate the expiration date.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

83. **Permit Expiration –** The owner shall submit an application for renewal at least six months but no earlier than eighteen months prior to the date of permit expiration.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

84. **Permit Expiration –** If an applicant submits a timely and complete application for an initial permit or renewal under this section, the failure of the source to have a permit or the operation of the source without a permit shall not be a violation of Article 3, Part II of 9 VAC 5 Chapter 80, until the Board takes final action on the application under 9 VAC 5-80-510.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

85. **Permit Expiration –** No source shall operate after the time that it is required to submit a timely and complete application under subsections C and D of 9 VAC 5-80-430 for a renewal permit, except in compliance with a permit issued under Article 3, Part II of 9 VAC 5 Chapter 80.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

86. **Permit Expiration** – If an applicant submits a timely and complete application under section 9 VAC 5-80-430 for a permit renewal but the Board fails to issue or deny the renewal permit before the end of the term of the previous permit, (i) the previous permit shall not expire until the renewal permit has been issued or denied and (ii) all the terms and conditions of the previous permit, including any permit shield granted pursuant to 9 VAC 5-80-500, shall remain in effect from the date the application is determined to be complete until the renewal permit is issued or denied.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

87. **Permit Expiration** – The protection under subsections F 1 and F 5 (ii) of section 9 VAC 5-80-430 F shall cease to apply if, subsequent to the completeness determination made pursuant to section 9 VAC 5-80-430 D, the applicant fails to submit by the deadline specified in writing by the Board any additional information identified as being needed to process the application.
(9 VAC 5-80-430 B, C and F, 9 VAC 5-80-490 D and 9 VAC 5-80-530 B)

88. **Recordkeeping and Reporting** – All records of monitoring information maintained to demonstrate compliance with the terms and conditions of this permit shall contain, where applicable, the following:

  a. The date, place as defined in the permit, and time of sampling or measurements.

  b. The date(s) analyses were performed.

  c. The company or entity that performed the analyses.

  d. The analytical techniques or methods used.

  e. The results of such analyses.

  f. The operating conditions existing at the time of sampling or measurement.

  (9 VAC 5-80-490 F)

89. **Recordkeeping and Reporting** – Records of all monitoring data and support information shall be retained for at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.
(9 VAC 5-80-490 F)

90. **Recordkeeping and Reporting** – The permittee shall submit the results of monitoring contained in any applicable requirement to DEQ no later than **<u>March 1</u>** and **<u>September 1</u>** of each calendar year. This report must be signed by a responsible official, consistent with 9 VAC 5-80-430 G, and shall include:

a. The time period included in the report. The time periods to be addressed are January 1 to June 30 and July 1 to December 31.

b. All deviations from permit requirements. For purposes of this permit, deviations include, but are not limited to:

(1) Exceedance of emissions limitations or operational restrictions;

(2) Excursions from control device operating parameter requirements, as documented by continuous emission monitoring, periodic monitoring, or compliance assurance monitoring which indicates an exceedance of emission limitations or operational restrictions; or,

(3) Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit.

c. If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that "no deviations from permit requirements occurred during this semi-annual reporting period."

(9 VAC 5-80-490 F)

91. **Annual Compliance Certification** – Exclusive of any reporting required to assure compliance with the terms and conditions of this permit or as part of a schedule of compliance contained in this permit, the permittee shall submit to EPA and DEQ no later than **March 1** each calendar year a certification of compliance with all terms and conditions of this permit including emission limitation standards or work practices. The compliance certification shall comply with such additional requirements that may be specified pursuant to §114(a)(3) and §504(b) of the federal Clean Air Act. This certification shall be signed by a responsible official, consistent with 9 VAC 5-80-430 G, and shall include:

a. The time period included in the certification. The time period to be addressed is January 1 to December 31.

b. The identification of each term or condition of the permit that is the basis of the certification.

c. The compliance status.

d. Whether compliance was continuous or intermittent, and if not continuous, documentation of each incident of non-compliance.

e. Consistent with subsection 9 VAC 5-80-490 E, the method or methods used for determining the compliance status of the source at the time of certification and over the reporting period.

f. Such other facts as the permit may require to determine the compliance status of the source.

g. One copy of the annual compliance certification shall be sent to EPA at the following address:

R3_APD_Permits@epa.gov

(9 VAC 5-80-490 K.5)

92. **Permit Deviation Reporting** – The permittee shall notify the DEQ as soon as practicable, but no later than four daytime business hours after discovery, of any deviations from permit requirements which may cause excess emissions for more than one hour, including those attributable to upset conditions as may be defined in this permit. In addition, within 14 days of the discovery, the permittee shall provide a written statement explaining the problem, any corrective actions or preventative measures taken, and the estimated duration of the permit deviation. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. The occurrence should also be reported in the next semi-annual compliance monitoring report pursuant to Condition 90 of this permit.
(9 VAC 5-80-490 F.2)

93. **Failure/Malfunction Reporting** – In the event that any affected facility or related air pollution control equipment fails or malfunctions in such a manner that may cause excess emissions for more than one hour, the owner shall, as soon as practicable but no later than four daytime business hours after the malfunction is discovered, notify the DEQ, by facsimile transmission, telephone or telegraph of such failure or malfunction and shall within 14 days of discovery provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the owner shall notify the DEQ.
(9 VAC 5-20-180 C)

94. **Failure/Malfunction Reporting** – The emission units that have continuous monitors subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not subject to the two week written notification.
(9 VAC 5-20-180 C, 9 VAC 5-40-50, and 9 VAC 5-50-50)

95. **Failure/Malfunction Reporting** – The emission units subject to the reporting and the procedure requirements of 9 VAC 5-40-50 C and the procedures of 9 VAC 5-50-50 C are:

a. Unit 1

b. Unit 2

c. Unit 3

d. Unit 4

e. Unit 5

(9 VAC 5-20-180 C, 9 VAC 5-40-50, and 9 VAC 5-50-50)

96. **Failure/Malfunction Reporting** –Each owner required to install a continuous monitoring system subject to 9 VAC 5-40-41 or 9 VAC 5-50-410 shall submit a written report of excess emissions (as defined in the applicable emission standard) to the board for every calendar quarter. All quarterly reports shall be postmarked by the thirtieth day following the end of each calendar quarter and shall include the following information:

a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h) or 9 VAC 5-40-41 B 6, any conversion factors used, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the source. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.

(9 VAC 5-20-180 C, 9 VAC 5-40-50, and 9 VAC 5-50-50)

97. **Failure/Malfunction Reporting** – All emission units not subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C must make written reports within 14 days of the malfunction occurrence.
(9 VAC 5-20-180 C, 9 VAC 5-40-50, and 9 VAC 5-50-50)

98. **Severability** – The terms of this permit are severable. If any condition, requirement or portion of the permit is held invalid or inapplicable under any circumstance, such invalidity or inapplicability shall not affect or impair the remaining conditions, requirements, or portions of the permit.
(9 VAC 5-80-490 G.1)

99. **Duty to Comply** – The permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Air Act or the Virginia Air Pollution Control Law or both and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or, for denial of a permit renewal application.
(9 VAC 5-80-490 G.2)

100. **Need to Halt or Reduce Activity not a Defense** – It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
(9 VAC 5-80-490 G.3)

101. **Permit Modification** – A physical change in, or change in the method of operation of, this stationary source may be subject to permitting under State Regulations 9 VAC 5-80-360, 9 VAC 5-80-1100, 9 VAC 5-80-1790, or 9 VAC 5-80-2000 and may require a permit modification and/or revisions except as may be authorized in any approved alternative operating scenarios.
(9 VAC 5-80-490 G, 9 VAC 5-80-490 L, 9 VAC 5-80-550, and 9 VAC 5-80-660)

102. **Property Rights** – The permit does not convey any property rights of any sort, or any exclusive privilege.
(9 VAC 5-80-490 G.5)

103. **Duty to Submit Information** – The permittee shall furnish to the Board, within a reasonable time, any information that the Board may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Board copies of records required to be kept by the permit and, for information claimed to be confidential, the permittee shall furnish such records to the Board along with a claim of confidentiality.
(9 VAC 5-80-490 G.6)

104. **Duty to Submit Information** – Any document (including reports) required in a permit condition to be submitted to the Board shall contain a certification by a responsible official that meets the requirements of 9 VAC 5-80-430 G.9.
(9 VAC 5-80-490 K.1)

105. **Duty to Pay Permit Fees** – The owner of any source for which a permit under 9 VAC 5-80-360 through 9 VAC 5-80-700 was issued shall pay permit fees consistent with the requirements of 9 VAC 5-80-310 through 9 VAC 5-80-350. The actual emissions covered

by the permit program fees for the preceding year shall be calculated by the owner and submitted to the Department by **April 15** of each year. The calculations and final amount of emissions are subject to verification and final determination by the DEQ.
(9 VAC 5-80-490 H)

106. **Fugitive Dust Emission Standards** – During the operation of a stationary source or any other building, structure, facility, or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions may include, but are not limited to, the following:

    a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;

    b. Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which may create airborne dust; the paving of roadways and the maintaining of them in a clean condition;

    c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty material. Adequate containment methods shall be employed during sandblasting or other similar operations;

    d. Open equipment for conveying or transporting material likely to create objectionable air pollution when airborne shall be covered or treated in an equally effective manner at all times when in motion; and,

    e. The prompt removal of spilled or tracked dirt or other materials from paved streets and of dried sediments resulting from soil erosion.

    (9 VAC 5-40-20 E, 9 VAC 5-50-90, and 9 VAC 5-50-50)

107. **Startup, Shutdown, and Malfunction** – At all times, including periods of startup, shutdown, soot blowing, and malfunction, owners shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Board, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
    (9 VAC 5-40-20 E, and 9 VAC 5-50-20 E)

108. **Alternative Operating Scenarios** – Contemporaneously with making a change between reasonably anticipated operating scenarios identified in this permit, the permittee shall record in a log at the permitted facility a record of the scenario under which it is operating.

The permit shield described in 9 VAC 5-80-500 shall extend to all terms and conditions under each such operating scenario. The terms and conditions of each such alternative scenario shall meet all applicable requirements including the requirements of 9 VAC 5 Chapter 80, Article 3.
(9 VAC 5-80-490 J)

109. **Inspection and Entry Requirements** – The permittee shall allow DEQ, upon presentation of credentials and other documents as may be required by law, to perform the following:

a. Enter upon the premises where the source is located or emissions-related activity is conducted, or where records must be kept under the terms and conditions of the permit.

b. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of the permit.

c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit.

d. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(9 VAC 5-80-490 K.2)

110. **Reopening For Cause** – The permit shall be reopened by the Board if additional federal requirements become applicable to a major source with a remaining permit term of three years or more. Such reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 9 VAC 5-80-430 F.

a. The permit shall be reopened if the Board or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

b. The permit shall be reopened if the administrator or the Board determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

c. The permit shall not be reopened by the Board if additional applicable state requirements become applicable to a major source prior to the expiration date established under 9 VAC 5-80-490 D.

(9 VAC 5-80-490 L)

111. **Permit Availability** – Within five days after receipt of the issued permit, the permittee shall maintain the permit on the premises for which the permit has been issued and shall make the permit immediately available to DEQ upon request.
(9 VAC 5-80-510 G)

112. **Transfer of Permits** – No person shall transfer a permit from one location to another, or from one piece of equipment to another.
(9 VAC 5-80-520)

113. **Transfer of Permits** – In the case of a transfer of ownership of a stationary source, the new owner shall comply with any current permit issued to the previous owner. The new owner shall notify the Board of the change in ownership within 30 days of the transfer and shall comply with the requirements of 9 VAC 5-80-560.
(9 VAC 5-80-520)

114. **Transfer of Permits** – In the case of a name change of a stationary source, the owner shall comply with any current permit issued under the previous source name. The owner shall notify the Board of the change in source name within 30 days of the name change and shall comply with the requirements of 9 VAC 5-80-560.
(9 VAC 5-80-520)

115. **Permit Revocation or Termination for Cause** – A permit may be revoked or terminated prior to its expiration date if the owner knowingly makes material misstatements in the permit application or any amendments thereto or if the permittee violates, fails, neglects or refuses to comply with the terms or conditions of the permit, any applicable requirements, or the applicable provisions of 9 VAC 5 Chapter 80 Article 3. The Board may suspend, under such conditions and for such period of time as the Board may prescribe, any permit for any of the grounds for revocation or termination or for any other violations of these regulations.
(9 VAC 5-80-490 G & L, 9 VAC 5-80-640 and 9 VAC 5-80-660)

116. **Duty to Supplement or Correct Application** – Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrections. An applicant shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit.
(9 VAC 5-80-430 E)

117. **Stratospheric Ozone Protection** – If the permittee handles or emits one or more Class I or II substances subject to a standard promulgated under or established by Title VI (Stratospheric Ozone Protection) of the federal Clean Air Act, the permittee shall comply with all applicable sections of 40 CFR Part 82, Subparts A to F.
(40 CFR Part 82, Subparts A-F)

118. **Asbestos Requirements** – The permittee shall comply with the requirements of National

Emissions Standards for Hazardous Air Pollutants (40 CFR 61) Subpart M, National Emission Standards for Asbestos as it applies to the following: Standards for Demolition and Renovation (40 CFR 61.145), Standards for Insulating Materials (40 CFR 61.148), and Standards for Waste Disposal (40 CFR 61.150).

(9 VAC 5-60-70 and 9 VAC 5-80-490 A)

119. **Accidental Release Prevention –** If the permittee has more, or will have more than a threshold quantity of a regulated substance in a process, as determined by 40 CFR 68.115, the permittee shall comply with the requirements of 40 CFR Part 68.

(40 CFR Part 68)

120. **Changes to Permits for Emissions Trading** – No permit revision shall be required under any federally approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.

(9 VAC 5-80-490 I)

121. **Emissions Trading** – Where the trading of emissions increases and decreases within the permitted facility is to occur within the context of this permit and to the extent that the regulations provide for trading such increases and decreases without a case-by-case approval of each emissions trade:

    a. All terms and conditions required under 9 VAC 5-80-110, except subsection N, shall be included to determine compliance.

    b. The permit shield described in 9 VAC 5-80-140 shall extend to all terms and conditions that allow such increases and decreases in emissions.

    c. The owner shall meet all applicable requirements including the requirements of 9 VAC 5-80-50 through 9 VAC 5-80-300.

(9 VAC 5-80-490 I)

Title IV (Phase II Acid Rain) Permit Allowances and Requirements

The Phase II Acid Rain permit is incorporated into this permit. The owners and operators of the source shall comply with the standard requirements and special provisions set forth in the application.
(9 VAC 5-80-430, 9 VAC 5-80-440, and 9 VAC 5-80-490 A.4.a and c, B, C, E, F, M, O and P)

122. **Statutory and Regulatory Authorities** – In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, Pages 62961-62967 and effective November 30, 2001, and Title 40, the Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality (DEQ) issues this permit pursuant to 9 VAC 5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Federal Operating Permit Article 3).
(9 VAC 5-80-490 B.2)

123. **SO_2 Allowance Allocations and NO_X Requirements for affected units -** Because the Ladysmith Combustion Turbine Station is not listed on Table 2 of 40 CFR 73.10, there are no SO2 allowance allocations for the years 2010 and beyond for Units 1 through 5. In addition, because the combustion turbines (Units 1 through 5) are fired with natural gas or No. 2 distillate fuel oil, they are not subject to NOx limitations under 40 CFR Part 76.
(9 VAC 5-80-490 A.4)

124. **Additional Requirements** – Virginia Electric and Power, Dominion – Ladysmith Combustion Turbine Station shall submit a complete permit application that includes all of the information required under 40 CFR §§72.21 and 72.31 at least six months, but no earlier than eighteen months, prior to the date of expiration of the existing Phase II Acid Rain permit. EPA forms shall be used.
(9 VAC 5-80-430 C.5)

125. **Notes -** SO_2 allowances may be acquired from other sources in addition to those allocated by U.S. EPA. No revision to this permit is necessary in order for the owners and operators of this unit to hold additional allowances recorded in accordance with 40 CFR Part 73. The owners and operators of this unit remain obligated to hold sufficient allowances to account for SO_2 emissions from this unit in accordance with 40 CFR 72.9(c)(1).
(9 VAC 5-80-420 C.1 and H.1 and 9 VAC 5-80-490 O)

126. **Notes** – This unit was not eligible for SO_2 allowance allocation by U.S. EPA under Section 405 of the Clean Air Act and the Acid Rain Program, so none were assigned in 40 CFR Part 73, Table 2.
(9 VAC 5-80-420 C.6)

127. **Justifications** – Unit 1, Unit 2,Unit 3,Unit 4, and Unit 5 are gas-fired or oil-fired units and are not subject to NO_X limitations under 40 CFR Part 76.
(9 VAC 5-80-420 D)

Cross State Air Pollution Rule (CSAPR)

128. **Cross State Air Pollution Rule (CSAPR)** – The permittee shall comply with all applicable cross-state air pollution rule (CSAPR) requirements (40 CFR Part 97, Subparts AAAAA – CCCCC) by the compliance date specified in 40 CFR 97, Subparts AAAAA – CCCCC, as amended.

(40 CFR Part 97, Subparts AAAAA - CCCCC and 9 VAC 5-80-490 B & C)

129. **CSAPR** – The Transport Rule (TR) subject units, and the unit-specific monitoring provisions, at this source are identified in the following table. These units are subject to the requirements for the TR NO_X Annual Trading Program (40 CFR Part 97, Subpart AAAAA), TR NO_X Ozone Season Trading Program (40 CFR Part 97, Subpart BBBBB), and TR SO_2 Group 1 Trading Program (40 CFR Part 97, Subpart CCCCC).

Unit ID: Unit 1, Unit 2, Unit 3, Unit 4, and Unit 5					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, subpart B (for SO_2 monitoring) and 40 CFR Part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR Part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR Part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR Part 75, Subpart E
SO_2		X	---------------		
NO_X	X	------------			
Heat input		X	---------------		

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

130. **CSAPR** –The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (TR NO_X Annual Trading Program), 97.530 through 97.535 (TR NO_X Ozone Season Trading Program), and 97.630 through 97.635 (TR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

131. **CSAPR** –Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at: http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

132. **CSAPR** –Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR 75.66 and 97.435 (TR NO_X Annual Trading Program), 97.535 (TR NO_X Ozone Season Trading Program), and/or 97.635 (TR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at: http://www.epa.gov/airmarkets/emissions/petitions.html.

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

133. **CSAPR** – Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (TR NO_X Annual Trading Program), 97.530 through 97.534 (TR NO_X Ozone Season Trading Program), and/or 97.630 through 97.634 (TR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (TR NO_X Annual Trading Program), 97.535 (TR NO_X Ozone Season Trading Program), and/or 97.635 (TR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

134. **CSAPR** – The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (TR NO_X Annual Trading Program), 97.530 through 97.534 (TR NO_X Ozone Season Trading Program), and 97.630 through 97.634 (TR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

(40 CFR Part 97, Subpart AAAAA – CCCCC and 9 VAC 5-80-490 B & C)

135. **CSAPR – TR NO_X Annual Trading Program requirements (40 CFR 97.406)**

a. Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

b. Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall comply with the

monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the TR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NO_X emissions requirements.

(1) TR NO_X Annual emissions limitation.

(a) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall hold, in the source's compliance account, TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Annual units at the source.

(b) If total NO_X emissions during a control period in a given year from the TR NO_X Annual units at a TR NO_X Annual source are in excess of the TR NO_X Annual emissions limitation set forth in paragraph (c)(1)(a) above, then:

(i) The owners and operators of the source and each TR NO_X Annual unit at the source shall hold the TR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(ii) The owners and operators of the source and each TR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(2) TR NO_X Annual assurance provisions.

(a) If total NO_X emissions during a control period in a given year from all TR NO_X Annual units at TR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the state for such control period exceed the state assurance level.

(i) The owners and operators shall hold the TR NO_X Annual allowances required under paragraph (c)(2)(a) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(ii) Total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iii) It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NO_X emissions from all TR NO_X Annual units at TR NO_X Annual sources in the during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Annual units at TR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

(iv) To the extent the owners and operators fail to hold TR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(a)(i) through (iii) above,

a) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

b) Each TR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(a) through (c) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(a) A TR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(b) A TR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(a) A TR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(a) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(b) A TR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(b)(i) and (2)(a) through (c) above for a control period in a given year must be a TR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA.

(6) Limited authorization. A TR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(a) Such authorization shall only be used in accordance with the TR NO_X Annual Trading Program; and

(b) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Annual allowance does not constitute a property right.

d. Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Annual allowances in accordance with 40 CFR part 97, subpart AAAAA.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR NO_X Annual source and each TR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(a) The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each TR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(b) All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Annual Trading Program.

(2) The designated representative of a TR NO_X Annual source and each TR NO_X Annual unit at the source shall make all submissions required under the TR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f. Liability.

(1) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual source or the designated representative of a TR NO_X Annual source shall also apply to the owners and operators of such source and of the TR NO_X Annual units at the source.

(2) Any provision of the TR NO_X Annual Trading Program that applies to a TR NO_X Annual unit or the designated representative of a TR NO_X Annual unit shall also apply to the owners and operators of such unit.

g. Effect on other authorities.

No provision of the TR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Annual source or TR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(40 CFR Part 97, Subpart AAAAA and 9 VAC 5-80-490 B & C)

136. **CSAPR –TR NO_X Ozone Season Trading Program Requirements (40 CFR 97.506)**

a. Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.513 through 97.518.

b. Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.530 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.531 (initial monitoring system certification and recertification

procedures), 97.532 (monitoring system out-of-control periods), 97.533 (notifications concerning monitoring), 97.534 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.535 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.530 through 97.535 shall be used to calculate allocations of TR NO_X Ozone Season allowances under 40 CFR 97.511(a)(2) and (b) and 97.512 and to determine compliance with the TR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.530 through 97.535 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. NO_X emissions requirements.

(1) TR NO_X Ozone Season emissions limitation.

(a) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.524(a) in an amount not less than the tons of total NO_X emissions for such control period from all TR NO_X Ozone Season units at the source.

(b) If total NO_X emissions during a control period in a given year from the TR NO_X Ozone Season units at a TR NO_X Ozone Season source are in excess of the TR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(a) above, then:

(i) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall hold the TR NO_X Ozone Season allowances required for deduction under 40 CFR 97.524(d); and

(ii) The owners and operators of the source and each TR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(2) TR NO_X Ozone Season assurance provisions.

(a) If total NO_X emissions during a control period in a given year from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.525(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.525(b), of multiplying—

(i) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(ii) The amount by which total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.

(b) The owners and operators shall hold the TR NO_X Ozone Season allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(c) Total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under 40 CFR 97.510(a) and the state's variability limit under 40 CFR 97.510(b).

(d) It shall not be a violation of 40 CFR part 97, subpart BBBBB or of the Clean Air Act if total NO_X emissions from all TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the TR NO_X Ozone Season units at TR NO_X Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.

(e) To the extent the owners and operators fail to hold TR NO_X Ozone Season allowances for a control period in a given year in accordance with paragraphs (c)(2)(a) through (c) above,

(i) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each TR NO_X Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(a) through (c) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart BBBBB and the Clean Air Act.

(3) Compliance periods.

(a) A TR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(b) A TR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.530(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(a) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraph (c)(1)(a) above for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for such control period or a control period in a prior year.

(b) A TR NO_X Ozone Season allowance held for compliance with the requirements under paragraphs (c)(1)(b)(i) and (2)(a) through (c) above for a control period in a given year must be a TR NO_X Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart BBBBB.

(6) Limited authorization. A TR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(a) Such authorization shall only be used in accordance with the TR NO_X Ozone Season Trading Program; and

(b) Notwithstanding any other provision of 40 CFR part 97, subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR NO_X Ozone Season allowance does not constitute a property right.

d. Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR NO_X Ozone Season allowances in accordance with 40 CFR part 97, subpart BBBBB.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.530 through 97.535, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.506(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(a) The certificate of representation under 40 CFR 97.516 for the designated representative for the source and each TR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.516 changing the designated representative.

(b) All emissions monitoring information, in accordance with 40 CFR part 97, subpart BBBBB.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NO_X Ozone Season Trading Program.

(2) The designated representative of a TR NO_X Ozone Season source and each TR NO_X Ozone Season unit at the source shall make all submissions required under the TR NO_X Ozone Season Trading Program, except as provided in 40 CFR 97.518. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f. Liability.

(1) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season source or the designated representative of a TR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the TR NO_X Ozone Season units at the source.

(2) Any provision of the TR NO_X Ozone Season Trading Program that applies to a TR NO_X Ozone Season unit or the designated representative of a TR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

g. Effect on other authorities.

No provision of the TR NO_X Ozone Season Trading Program or exemption under 40 CFR 97.505 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NO_X Ozone Season source or TR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(40 CFR Part 97, Subpart BBBBB and 9 VAC 5-80-490 B & C)

137. **CSAPR - TR SO_2 Group 1 Trading Program requirements (40 CFR 97.606) –**

a. Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

b. Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general

requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of TR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c. SO_2 emissions requirements.

(1) TR SO_2 Group 1 emissions limitation.

(a) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO_2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all TR SO_2 Group 1 units at the source.

(b) If total SO_2 emissions during a control period in a given year from the TR SO_2 Group 1 units at a TR SO_2 Group 1 source are in excess of the TR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(a) above, then:

(i) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall hold the TR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(ii) The owners and operators of the source and each TR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(2) TR SO_2 Group 1 assurance provisions.

(a) If total SO_2 emissions during a control period in a given year from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(i) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(ii) The amount by which total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.

(b) The owners and operators shall hold the TR SO_2 Group 1 allowances required under paragraph (c)(2)(a) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(c) Total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(d) It shall not be a violation of 40 CFR part 97, subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the TR SO_2 Group 1 units at TR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.

(e) To the extent the owners and operators fail to hold TR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(a) through (c) above,

(i) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each TR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(a) through (c) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(a) A TR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(b) A TR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(a) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(a) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(b) A TR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(b)(i) and (2)(a) through (c) above for a control period in a given year must be a TR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart CCCCC.

(6) Limited authorization. A TR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(a) Such authorization shall only be used in accordance with the TR SO_2 Group 1 Trading Program; and

(b) Notwithstanding any other provision of 40 CFR part 97, subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO_2 Group 1 allowance does not constitute a property right.

d. Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO_2 Group 1 allowances in accordance with 40 CFR part 97, subpart CCCCC.

(2) This permit incorporates the TR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR part 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E), Therefore, the Description of TR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e. Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of five years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(a) The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each TR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(b) All emissions monitoring information, in accordance with 40 CFR part 97, subpart CCCCC.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO_2 Group 1 Trading Program.

(2) The designated representative of a TR SO_2 Group 1 source and each TR SO_2 Group 1 unit at the source shall make all submissions required under the TR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f. Liability.

(1) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 source or the designated representative of a TR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO_2 Group 1 units at the source.

(2) Any provision of the TR SO_2 Group 1 Trading Program that applies to a TR SO_2 Group 1 unit or the designated representative of a TR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

g. Effect on other authorities.

No provision of the TR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO_2 Group 1 source or TR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(40 CFR Part 97, Subpart CCCCC and 9 VAC 5-80-490 B & C)

APPENDIX A

CUSTOM FUEL MONITORING SCHEDULE REQUEST AND THE EPA LETTER OF APPROVAL

Effective for Unit 1 and Unit 2 Only
(Units 3, 4, and 5 are subject to 40 CFR 60, Subpart KKKK and not included in this letter)

Dominion Generation

Dominion

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

December 3, 2002

RECEIVED
DEC 9 2002

Mr. James Hagedorn
USEPA
Air Protection Division, 3AP12
1650 Arch Street
Philadelphia, PA 19103-2029

Re: Ladysmith Combustion Turbine Station
Custom Fuel Monitoring Schedule

Dear Mr. Hagedorn:

Dominion Generation operates the Ladysmith Combustion Turbine Station located in Caroline County, VA that became operational in June 2001. The two General Electric 7 FA simple-cycle combustion turbines operate primarily on natural gas, but they are capable of combusting distillate fuel oil (low sulfur #2 oil). The units are subject to NSPS Subpart GG, 40 CFR Part 75 (the Acid Rain provisions), and to a Virginia stationary source permit to construct and operate.

We request that EPA Region 3: 1) approve a custom fuel monitoring schedule for the analysis of sulfur in the natural gas combusted at Ladysmith Combustion Turbine Station; 2) approve that samples taken at our Chesterfield Station fulfill the fuel analysis requirement for the Ladysmith Station; and, 3) waive the requirement to analyze nitrogen in the natural gas at the Ladysmith Station.

We request to be relieved of the requirements at 40 CFR 60.334(b) and 60.335(d) to monitor, determine, and record the sulfur content of the fuels fired in the turbines. Instead, the facility proposes to follow applicable sulfur content determination and monitoring requirements for pipeline natural gas and fuel oil in 40 CFR Part 75, Appendix D.

We recognize that Subpart GG establishes the following sulfur dioxide (SO_2) emissions limitations:

- No owner or operator shall cause to be discharged into the atmosphere from any stationary gas turbine any gases containing SO_2 in excess of 0.015% by volume at 15% oxygen and on a dry basis; or,

- No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight.

As indicated above, we propose to follow applicable sulfur content determination and monitoring requirements in Appendix D of 40 CFR Part 75. Given that the Acid Rain Program is recognized as more stringent than NSPS requirements, compliance with Subpart GG will be readily demonstrated. In a determination dated May 5, 2002 (see EPA Applicability Determination Index, Control Number 0200038, copy attached), EPA Region 3 approved similar requests for Pleasants Energy, LLC and for Armstrong Energy, LLLP, both of which are operated by Dominion.

In a letter dated July 2, 1998, EPA Region 3 approved the custom fuel monitoring schedule for our Darbytown Station (see EPA Applicability Determination Index, Control Number 9800110, copy attached). Our Ladysmith Station is located on the same pipeline that supplies our Darbytown and Chesterfield Stations, as is the Doswell Limited Partnership Station. In that same determination, Region 3 approved the use of natural gas samples taken at our Chesterfield Station to fulfill the fuel analysis requirement for the Darbytown Station. The Doswell facility had previously been granted approval for a custom fuel monitoring schedule (see ADI Control Number 9800053, January 9, 1998, copy attached). Given that at least two determinations have been made regarding natural gas in this pipeline, we request that the custom fuel monitoring schedule be approved without further study or analysis of additional data.

In addition, we request waiving of the requirement to analyze nitrogen in the natural gas.

Please contact Mr. Philip Knause at (804) 273-2946, or via email at Philip_Knause@Dom.com if you have any questions.

Yours Truly,

Cathy C. Taylor

Cathy C. Taylor
Director – Electric Environmental Services

cc: Mr. James LaFratta
VADEQ Fredericksburg Satellite Office
806 Westwood Office Park
Fredericksburg, VA 22401

#40960

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

RECEIVED
DEC 19 2002
FUO

DEC 17 2002

Cathy C. Taylor, Director
Dominion Generation Environmental Services
5000 Dominion Boulevard
Glen Allen, Virginia, 23060

Dear Ms. Taylor:

The Philadelphia Regional Office of the U.S. Environmental Protection Agency (Region III) has received and reviewed your letter, dated December 3, 2002, requesting approval to use several alternative monitoring methods to the ones specified under Subpart GG of Part 60 for emission sources covered by the New Source Performance Standards (NSPS) program at the Company's Ladysmith Combustion Turbine Station. Dominion operates two General Electric 7 FA simple cycle combustion turbines at the station that primarily burn natural gas but do have the capability of burning distillate fuel oil #2. The Company is specifically requesting that EPA approve; 1) a custom fuel monitoring schedule for sulfur analysis for the pipeline-quality natural gas combusted in the turbines; 2) the use of Chesterfield Station samples for showing pipeline gas sulfur content; 3) a waiver of the requirement to monitor natural gas nitrogen content; and 4) approval to use the Acid Rain Part 75, Appendix D procedures for measuring the sulfur content in both the natural gas and distillate fuel oil combusted in the turbines.

After careful consideration of the facts presented in the Company's December letter, Region III has decided to approve these requests since similar requests have been approved in the past by EPA in both Region III and other EPA Regional Offices for similarly situated stations. These approvals are consistent with past EPA determinations as currently presented on the Agency's Applicability Determination Index database. EPA's 1987 National Policy covering Subpart GG gas turbines acknowledges the fact that fuel bound nitrogen in pipeline-quality natural gas fuel does not appreciably contribute to the formation of nitrogen oxides upon combustion. Another factor taken into consideration is the fact that Region III has already approved similar exemptions and alternatives for other turbine stations that also combust the same natural gas fuel as the Ladysmith Station from the same gas pipeline. If you should have any comments or questions in regard to this matter, do not hesitate to contact James W. Hagedorn, of my staff, at (215) 814-2161.

Sincerely,

Judith M. Katz, Director
Air Protection Division

cc: Jim LaFratta, VADEQ-Fredericksburg Office

APPENDIX B

FUEL TRANSFERS/SHIPMENT RECEIPT DEFINED

No. 2 Distillate Fuel Oil Transfers/Shipment Receipt

Dominion – Ladysmith CT Station defines fuel oil transfer/shipment receipt as a series of truck transport loads from a vendor's fuel oil tank to the facility's 2,700,000 gal tanks. Prior to the fuel transfer/shipment receipt, the vendor shall supply Dominion – Ladysmith CT Station personnel with copies of fuel contracts, tariff sheets and/or bills of laden with a maximum total sulfur specification that meets the definition of No. 2 distillate fuel oil. These certifications will provide, at a minimum, the information required in Condition 39 of this permit. Copies of the fuel supplier certifications shall be retained at the CT site.

Upon receipt of delivered oil, the receiving tank(s) at the CT site will be sampled for sulfur content prior to combustion. The sampling will be done as referenced in Condition 38 of the CT permit. Copies of these analyses will also be retained at the CT site as required by their permit.

APPENDIX C

ALTERNATE OPERATING SCENARIO – RE-TUNING

ALTERNATE OPERATING SCENARIOS – RE-TUNING

Alternate 1 – Units 1 – 5 (Natural Gas)
&
Alternate 2 – Units 1 – 5 (No. 2 Distillate Oil)

In order to meet NO_X emission limits, Units 1 – 5 may require periodic re-tuning based upon maintenance or a change in test methods for fuel-bound nitrogen. Re-tuning may require for either or both fuels. During retuning events, the unit(s) is ramped up at 5 MW increments all the way to 100% load. At each 5 MW increment, the unit(s) is tested and data is collected to produce a control curve for the units control system. The unit(s) is dropped back to minimum load, the new control curve is entered, and then the unit(s) is then ramped back up and data points are taken to ensure that the control curve meets the NO_X emission limits. This process is repeated until the unit is properly tuned. NO_X emissions may exceed short term NOX emission limits during re-tuning events. Re-tuning events are infrequent (typically once every 450 starts or 5 – 12 years; however, could be longer depending on the cause of the re-tuning). Consequently, Dominion is proposing a variance from NO_X emission limits during re-tuning events.

Excess Emissions – Re-tuning: Excess emissions resulting from the re-tuning of the combustion turbines shall be permitted provided that:

a. Best operational practices are adhered to and the duration of excess emissions shall be minimized but in no case exceed twelve hours per combustion turbine's re-tuning event in any twenty-four hour period. The operator may request additional hours from the DEQ.

b. During each Unit 1 and Unit 2 re-tuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (60.330 et seq.).

c. During each Unit 3, Unit 4, and Unit 5 re-tuning event, NO_X emission concentrations, based on an hourly average, shall not exceed the NO_X standards of the New Source Performance Standards (NSPS) 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines (60.4300 et seq.).

d. The permittee shall notify the Regional Air Compliance Manager of the DEQs NRO, no less than twenty-four hours prior to each combustion turbine's re-tuning event. The notification shall include, but is not limited to, the following information.

   (1) Identification of the specific combustion turbine to be re-tuned.
   (2) Reason for the re-tuning event.
   (3) Measures that will be taken to minimize the length of the re-tuning event.

e. The permittee shall furnish a written report to the Regional Air Compliance Manager of the DEQs NRO of all pertinent facts concerning the re-tuning event, as soon as practicable but not later than fourteen business days after the re-tuning event. The notification shall include, but is not limited to, the following information.

(1) Identification of the combustion turbine that was re-tuned.
(2) The magnitude of excess emissions for each combustion turbine, any conversion factors used in the calculation of the excess emissions, and the date and time of commencement and completion of each period of excess emissions.

f. NO_X emissions during each combustion turbine's re-tuning event shall be recorded and included in the associated quarterly reports and in the total annual emissions.

The re-tuning event for each combustion turbine shall be identified on the Data Acquisition Report.

APPENDIX D

ALTERNATE OPERATING SCENARIOS - FUEL TYPE TRANSFER
Excerpt from Facility Operating Procedures

At the CEMS Polling Computer

- ☐ After Unit is on line (approx. 30 minutes after FIRE) verify CEMS initiates a CAL by monitoring the POLLING Computer for "C" flags
- ☐ CEMS will CAL for approx. 25 min.
- ☐ After CAL is complete, check CAL REPORT on polling computer to assure no parameters are OOC.
- ☐ IF a parameter goes OOC during a CAL a "T" flag will appear on that parameter, the Technician MUST put PNOXL, PNOXH and QO2D in MAINT and perform a manual CAL to correct the problem. THEN a "hands off" cal needs to be performed.
- ☐ Check QNOXA15 to make sure that is below 9ppm when on Natural Gas and or 42ppm when on Liquid Fuel.
  - Start up - This must occur within 2 one hour averaging periods (2 CEMS hours).
  - Fuel Transfer - This must occur within 3 one hour averaging periods (3 CEMS hours).
  - Shut Down - This must occur within 2 one hour averaging periods (2 CEMS hours).

  If the unit can not come into compliance within the above time frames the unit must be immediately shut down.
- ☐ All alarms on the CEMS Polling Computer must be addressed immediately to determine cause and appropriate action.

Fuel Transfers

Natural Gas to Liquid Fuel – Auto / Manual Operator Initiated Transfer

- ☐ If Manually transferring fuels lower the load on the Unit (40 - 60MW), Initiate transfer and enter the start time of the transfer in the station log.
- ☐ If Auto transfer due to loss of gas pressure. Select PRESELECTED load to current MW to keep unit from continuing to runback and eventually off line. Enter the start time of the transfer in the station log.
- ☐ Confirm unit has successfully transferred to liquid fuel.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits.
- ☐ Raise unit load to above Water Injection approximately 80MW.
- ☐ Confirm Water Injection system has started and flow is established.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits

- ☐ Confirm NOX below 42ppm on CEMS Polling Computer.
- ☐ Enter the end time of the transfer in the station log.
- ☐ After verifying proper unit operation resume unit loading to meet required dispatch.
- ☐ At the CEMS Polling Computer the alarm for exceedance should be acknowledged with a fuel transfer as the reason code.

Liquid Fuel to Natural Gas - Manual Operator Initiated Transfer

- ☐ Lower unit load to 12MW.
- ☐ Initiate transfer.
- ☐ Enter the start time of the transfer in the station log.
- ☐ Confirm unit has transferred to natural gas.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits
- ☐ Raise load to above Mode 6 approximately 90MW.
- ☐ Observe Exhaust Spreads and Temperatures, confirm within normal limits
- ☐ Confirm NOX below 9ppm on CEMS Polling Computer.
- ☐ Enter the end time of the transfer in the station log.
- ☐ After verifying proper unit operation resume unit loading to meet required dispatch.
- ☐ At the CEMS Polling Computer the alarm for exceedance should be acknowledged with a fuel transfer as the reason code.

APPENDIX E

ACID RAIN PERMIT APPLICATION

Dominion Resources Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
Web Address: www.dom.com

Dominion®

CERTIFIED MAIL, RETURN RECEIPT REQUESTED

VA DEPARTMENT OF ENVIRONMENTAL QUALITY
NORTHERN
JUN 25 2014
REGIONAL OFFICE
091 JML
WOODBRIDGE, VA

June 19, 2014

Mr. Jim LaFratta
Air Permit Manager
Virginia Department of Environmental Quality
Northern Virginia Regional Office
13901 Crown Court
Woodbridge, VA 22193

RE: **Ladysmith Power Station: Acid Rain Renewal Application DEQ Air Reg. 40960**

Dear Mr. LaFratta:

Enclosed please find the Acid Rain renewal application for Ladysmith CT Station. A copy of the Certificate of Representation report from the CAMD website has also been included for your reference.

If you have any questions, please feel free to contact Liz Willoughby at (804) 273-3740 or Elizabeth.A.Willoughby@dom.com.

Sincerely,

Cathy C. Taylor

Cathy C. Taylor
Director, Electric Environmental Services

Enclosures: Ladysmith CT Station Acid Rain Permit Application
Certificate of Representation

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

EPA

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised X for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Dominion - Ladysmith CT Station	VA	7838

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
1	Yes
2	Yes
3	Yes
4	Yes
5	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Permit Requirements

STEP 3

Read the standard requirements.

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

Recordkeeping and Reporting Requirements, Cont'd.

STEP 3, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

STEP 3, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

STEP 4
Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Jeffrey Heffelman	
Signature [signature]	Date 6-18-14

Reports and Queries
Certificate of Representation
09/09/2013

Facility Information

Facility ID (ORISPL): 7839 **Facility Name:** Ladysmith Combustion Turbine Sta **State:** VA

County: Caroline **EPA AIRS ID:** 5103300040 **Latitude:** 38.5442 **Longitude:** -77.7714

Facility Detail (Mini Detail)

Primary Representative Information

Name: Edward H Baine

Company: Dominion Resources Services, Inc

Title: Vice President Power Generation System Operations

Address: VA 23060

Phone: (804) 273-3592

Fax: (804) 273-3714

Alternate:

Email: dominion.system.dr@dom.com

People Detail Layout (Multiple)

Alternate Representative Information

Name: Jeffrey C Heffelman

Company: Virginia Electric & Power Company

Title: Director, F & H Station II

Address: VA 22026

Phone: (703) 441-3880

Fax: (703) 441-3897

Alternate:

Email: jeffrey.c.heffelman@dom.com

People Detail Layout (Multiple)

Current Representatives

Program	Primary Representative, Effective Date	Alternate Representative, Effective Date	Primary Representative, End Date	Alternate Representative, End Date
ARP	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIRNOX	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIROS	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
CAIRSO2	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 04/08/2011		
TRNOX	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011		
TRNOXOS	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011		

TRSO2G1	Edward H Baine, 06/28/2013	Jeffrey C Heffelman, 09/27/2011			

Basic Table Layout

Units

Unit ID	Program	Unit Classification	Operating Status	Unit Type	Indian Country	Source Category	NAICS Code	Commence Operation Date	Commence Operation Date Code	Comm. Commercial Operation Date	Commence Commericial Operation Date Code	Unit Monitoring Certification Begin Date
1	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/31/2001
1	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2008
1	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2008
1	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2009
1	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2003
1	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2012
1	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	05/01/2012
1	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/31/2001	A	05/31/2001	A	01/01/2012
2	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/23/2001
2	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2008
2	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2008
2	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2009
2	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2003
2	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2012
2	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	05/01/2012
2	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/23/2001	A	05/23/2001	A	01/01/2012

3	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/22/2008
3	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2009
3	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/19/2008
3	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2012
3	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	05/01/2012
3	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	05/19/2008	A	05/22/2008	A	01/01/2012
4	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/07/2008
4	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2009
4	NBP	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	06/03/2008
4	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2012
4	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	05/01/2012
4	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	06/03/2008	A	06/07/2008	A	01/01/2012
5	ARP	Phase 2	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	CAIRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	CAIROS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric	03/19/2009	A	03/22/2009	A	03/22/2009

							power generation					
5	CAIRSO2	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	03/22/2009
5	TRNOX	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	01/01/2012
5	TRNOXOS	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	05/01/2012
5	TRSO2G1	Affected	Operating	CT	No	Electric Utility	Fossil fuel electric power generation	03/19/2009	A	03/22/2009	A	01/01/2012

Basic Table Layout

Generator Information

Generator ID	Unit ID	ARP Nameplate Capacity	CAIR/Transport Rule Nameplate Capacity	Effective Date
1	1	178.5	178.5	06/04/2007
2	2	178.5	178.5	06/04/2007
3	3	192.1	192.1	01/08/2008
4	4	192.1	192.1	01/08/2008
5	5	192.1	192.1	01/08/2008

Basic Table Layout

Current Owners and Operators

Unit ID	Owner/Operator Company Name	Type	Effective Date	End Date
1	Dominion Generation	Operator	03/07/2003	
1	Virginia Electric & Power Company	Owner	03/07/2003	
2	Dominion Generation	Operator	03/07/2003	
2	Virginia Electric & Power Company	Owner	03/07/2003	
3	Dominion Generation	Operator	12/26/2007	
3	Virginia Electric & Power Company	Owner	12/26/2007	
4	Dominion Generation	Operator	12/26/2007	
4	Virginia Electric & Power Company	Owner	12/26/2007	
5	Dominion Generation	Operator	01/08/2008	
5	Virginia Electric & Power Company	Owner	01/08/2008	

Basic Table Layout